2000 ANNUAL REPORT

"WE'RE DETERMINED TO UNLOCK THE **VALUE** IN PETRO-CANADA'S PORTFOLIO AND SEE THAT IT IS REFLECTED IN OUR SHARE PRICE."

RON BRENNEMAN, PRESIDENT AND CEO, MARCH 2000

PETRO-CANADA

HIGHLIGHTS

(stated in millions of Canadian dollars, unless otherwise indicated)	**2000**	1999	1998
FINANCIAL			
Earnings from operations (in 2000 and 1998, before reorganization costs)	**860**	236	130
Net earnings	**893**	233	95
Cash flow	**1 870**	964	830
Per share (dollars)			
Earnings from operations (in 2000 and 1998, before reorganization costs)	**3.16**	0.87	0.48
Net earnings — basic	**3.28**	0.86	0.35
Net earnings — fully diluted	**3.22**	0.86	0.35
Cash flow	**6.87**	3.55	3.06
Dividends	**0.40**	0.34	0.32
Expenditures on property, plant and equipment and exploration	**1 203**	1 021	1 116
Return on capital employed (per cent)	**16.6**	5.6	3.0
Operating return on capital employed (per cent) (in 2000 and 1998, before reorganization costs)	**16.0**	5.6	3.6
Cash flow return on capital employed (per cent)	**33.2**	18.6	16.3
Debt	**1 774**	1 711	1 829
Debt to debt plus equity (per cent)	**27.9**	29.5	31.7
Debt to cash flow (times)	**0.9**	1.8	2.2
OPERATING			
Crude oil and field natural gas liquids production, net before royalties (thousands of barrels per day)	**89.2**	95.3	101.1
Natural gas production, net before royalties, excluding injectants (millions of cubic feet per day)	**738**	719	722
Proved oil and field natural gas liquids reserves, net before royalties (millions of barrels)	**414**	476	476
Proved natural gas reserves, net before royalties (trillions of cubic feet)	**2.3**	2.5	2.5
Refined petroleum product sales (thousands of cubic metres per day)	**55.4**	51.2	49.1
Refinery crude capacity utilization (per cent)	**101**	100	95

TABLE OF CONTENTS

WE HAVE SHARPENED OUR STRATEGIC **FOCUS** ON THE BEST ASSETS WITHIN OUR FOUR CORE BUSINESSES AND THE BEST OPPORTUNITIES IN OUR GROWTH PORTFOLIO.

WITH **DISCIPLINE** IN ALLOCATING CAPITAL AND MANAGING CONTROLLABLES, WE INTEND TO ACHIEVE FIRST-QUARTILE PERFORMANCE IN EACH OF OUR BUSINESSES.

WE WILL BUILD ON THE FINANCIAL AND ORGANIZATIONAL **CAPABILITY** TO CARRY OUT OUR PLANS.

FIVE-YEAR SHARE PRICE PERFORMANCE

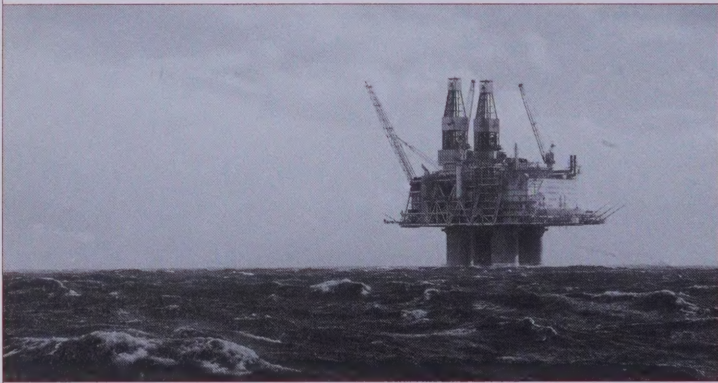
During 2000, Petro-Canada shares appreciated 87 per cent.

(December 31, 1995 = 100)
Changes in yearly closing values for Petro-Canada shares compared with the Toronto Stock Exchange (TSE) 300 index, the TSE Integrated Oils sub-index and the TSE Oil & Gas Producers sub-index.

- Petro-Canada
- TSE 300 index
- Integrated Oils sub-index
- Oil & Gas Producers sub-index

CORE BUSINESSES AT A GLANCE

EAST COAST OFFSHORE



Business Description

- Explores for, develops, produces and markets oil from offshore Newfoundland
- 20% interest in the producing Hibernia oil field
- 34% interest in, and operator of, the Terra Nova oil development
- Interests in other significant discoveries and exploration acreage
- Exploring in emerging gas play area offshore Nova Scotia

Strategies

- Expand light oil production base from offshore Newfoundland, capitalizing on experience gained in developing the Hibernia oil field
- Pursue high-potential exploration plays, in both oil and natural gas

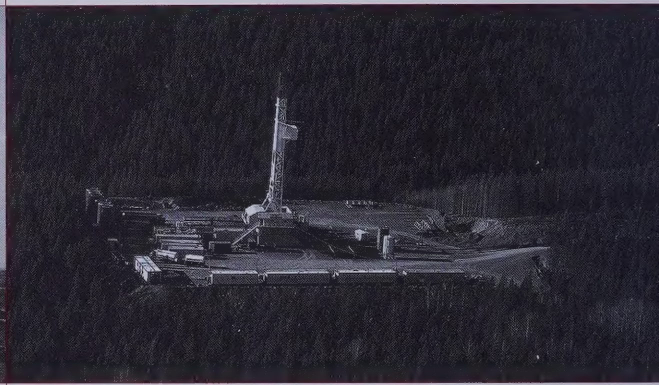
2000 Achievements

- Petro-Canada's share of Hibernia production increased 45% to 28 900 barrels per day
- Continued Hibernia development, including successful drilling of the first two wells in the Avalon formation
- Safe delivery of Terra Nova production vessel to Bull Arm, Newfoundland
- Advanced White Rose and Hebron/Ben Nevis projects
- Secured new exploration acreage for the fifth consecutive year
- Shot 4 200 square kilometres of 3-D seismic across Flemish Pass Basin and 2 000 square kilometres on the Scotian Shelf

Plans for 2001

- Maintain strong production from Hibernia, continue drilling in Hibernia and Avalon formations
- Complete Terra Nova development and begin production
- Evaluate Flemish Pass seismic and secure rig to drill first well as early as 2002
- File Development Application and complete front-end engineering design studies for potential White Rose development
- Evaluate Scotian Shelf seismic and secure rig to drill first well as early as 2002

NATURAL GAS



Business Description

- Explores for, produces and markets natural gas and associated liquids
- Among the largest producers in Western Canada
- Exploring in the Alberta Foothills, northeastern British Columbia, and the Mackenzie Delta

Strategies

- Maximize profitability in Western Canada through focused exploration and development in our core areas — the Alberta Foothills, northeastern British Columbia, west-central and southeastern Alberta
- Pursue high-potential exploration plays in the Mackenzie Delta

2000 Achievements

- Increased daily production from 719 to 738 million cubic feet per day, despite sales of non-core, producing properties; also produced 11 000 barrels of natural gas liquids per day
- Added 301 billion cubic feet of proved reserves through the drill bit, replacing 111% of 2000 production
- Achieved finding and development costs of $1.12 per thousand cubic feet of gas equivalent
- Continued exploration and development success in the Alberta Foothills
- Completed disposition of non-core properties
- Increased interests to 590 000 net acres in the Mackenzie Delta, completed seismic program, and mobilized rig to drill first well in early 2001

Plans for 2001

- Active drilling in the Alberta Foothills, northeastern British Columbia, west-central and southeastern Alberta
- Drill first exploration well and shoot additional seismic in the Mackenzie Delta

PETRO-CANADA IS A MAJOR OIL AND GAS COMPANY AND A LEADER IN THE CANADIAN PETROLEUM INDUSTRY. WE ARE STRATEGICALLY **FOCUSED** ON FOUR CORE BUSINESSES.

OIL SANDS

Business Description

- Phased development of extensive oil sands properties in northern Alberta
- 12% working interest in the Syncrude oil sands mining operation at Fort McMurray, Alberta
- 100% working interest in the MacKay River *in situ* oil sands project
- Interests in more than 200 000 net acres of prospective *in situ* oil sands leases

Strategies

- Increase our share of Syncrude production to more than 50 000 barrels per day by the end of 2007, through phased expansion
- Pursue *in situ* oil sands developments and evaluate potential integration with our Edmonton refinery

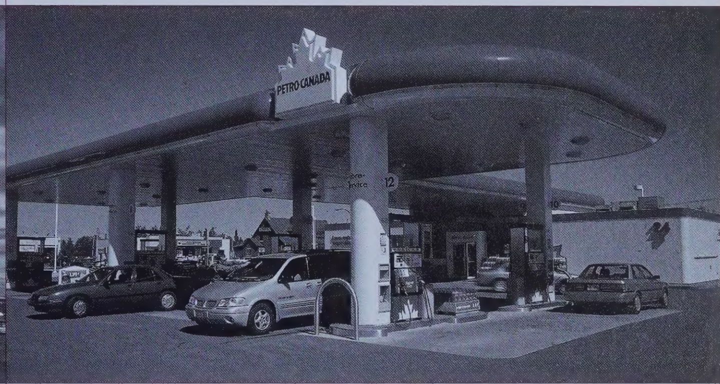
2000 Achievements

- Completed second phase of Syncrude expansion, including start-up of Aurora Mine Train 1 and completion of debottlenecking
- Started construction of production facilities for 30 000-barrel-per-day MacKay River *in situ* project
- Petro-Canada's share of Syncrude production averaged 24 300 barrels per day

Plans for 2001

- Participate in Phase 3 of the Syncrude expansion
- Continue construction of production facilities at MacKay River for start-up in late 2002
- Assess candidate properties for next *in situ* development
- Begin stakeholder consultations concerning future *in situ* development and potential Edmonton refinery conversion

DOWNSTREAM



Business Description

- Converts crude oil into refined products, including gasoline, diesel, jet fuel and asphalt
- Owns and operates three refineries in Canada, representing 18% of Canada's total refining capacity
- Markets refined petroleum products and services through a nationwide network of retail and wholesale outlets
- Canada's second largest marketer of refined petroleum products, with a 17% share of market
- Manufactures and markets high-quality specialty lubricants

Strategies

- Generate superior returns and growth by focusing on first-quartile cost performance, building on our strength in niche markets, being the brand of choice for Canadian gasoline consumers, and maximizing sales of high-margin specialty lubricants

2000 Achievements

- Increased total crude processed by 3% to 50 300 cubic metres per day, achieving refinery crude capacity utilization of 101%
- Sustained high conversion unit reliability of over 90% at our three refineries and lubricants plant
- Achieved throughput per retail site of 3.7 million litres
- Increased sales of high-margin lubricants by 10%

Plans for 2001

- Maintain high refinery reliability and utilization
- Begin refinery modifications to meet future environmental regulations for fuels
- Accelerate roll-out of new-image retail sites
- Increase retail throughput per site and sales of non-petroleum products and services
- Further increase lubricant sales into higher margin food-grade, industrial, and environmentally sensitive product markets

TO OUR SHAREHOLDERS

Petro-Canada capitalized on an exceptionally strong business environment in 2000 to deliver best-ever financial results. With high prices for our crude oil and natural gas production and improved refining margins, we stretched production to maximize volume performance, while reducing ongoing costs across the business.

The combination of favourable business conditions, our response to that environment, and the early impact of our actions to improve performance gave us record net earnings of $893 million ($3.28 per share), compared with $233 million in 1999.

During 2000, we established a clear game plan for performance improvement and growth, based on a sharp strategic focus, disciplined execution, and strong financial and organizational capability. And we made a good start on implementation.

To improve overall performance, we assessed each and every significant asset to ensure it is capable of delivering cost-of-capital returns. As a result of that examination, we divested a number of non-core oil and gas properties and our natural gas liquids business. For a number of other assets, we developed business plans to ensure they can meet that performance standard. We also made significant progress in reducing ongoing G&A and overhead costs and initiated steps toward first-quartile operating costs in all our major facilities.

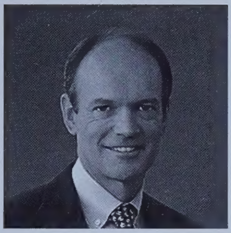
During 2000, we reorganized our Downstream along functional lines to gain efficiency and establish a platform for improved performance. We increased refinery reliability to more than 90 per cent from below 80 per cent last year. And we increased high-margin components of our lubricants sales mix, which is a key to our plan for success in the lubricants business.

We continue to critically examine costs in every aspect of our business. The format of this annual report is itself an outcome of that review. By focusing on full and clear disclosure, while eliminating expensive features, we have shortened the report and cut costs in half. We can provide photos and descriptive material more economically on our Web site, and I invite you to visit www.petro-canada.ca

In 2001, we will drive forward with our strategic plan, aimed at achieving the full potential of our four core businesses — East Coast offshore, oil sands, natural gas and the Downstream — while aggressively pursuing our best opportunities for value-creating growth.

Much of our growth for the early part of this decade will come from resources we have already discovered, notably on the East Coast and in the oil sands of Alberta.

Our Terra Nova offshore oil development will come on stream later in 2001, ramping up early next year to peak production. A development application has been filed for the White Rose oil field to establish the basis for economic and engineering evaluation, and we continue to assess Hebron/Ben Nevis to identify the most economic development plan.



This year we began development of our extensive oil sands leases with a start on construction of our first *in situ* production project. We expect MacKay River will produce 30 000 barrels per day for Petro-Canada over 25 years, and we're working this winter to assess candidate properties for the next development. We are also evaluating the economic potential for integrating oil sands development with our first-quartile refinery in Edmonton.

With a view to the longer term, we are positioning Petro-Canada for potential growth projects later in the decade, with acreage positions in deeper water off the East Coast and in the Mackenzie Delta in the Northwest Territories. We have begun exploration with seismic programs in the oil-prone Flemish Pass area offshore Newfoundland and the gas-prone Scotian Shelf off Nova Scotia. In the Mackenzie Delta, we identified several prospects through seismic in the winter of 1999-2000, and mobilized a new Arctic rig to spud the first Delta well in a decade in February 2001.

In my first year as CEO, I have enjoyed tremendous support from Petro-Canada's employees. Our people have energetically taken up the challenge of improving overall performance. Their commitment and professionalism give me great confidence that we will indeed attain our goal of realizing the full potential of the company's assets. And it is gratifying to see that the market has responded positively to our plans for performance improvement and growth.

With the business environment remaining strong into the New Year, and our performance initiatives accelerating, we anticipate another good year in 2001. We plan to invest $1.5 billion to strengthen our base business and advance our growth opportunities.

In November, we initiated a Normal Course Issuer Bid, under which we may buy back and cancel up to 22 million shares, almost 10 per cent of our publicly held shares. With exceptional cash flow and proceeds from asset sales, we have more cash than we require to fund our strong capital investment program and other needs, and we see the buyback as a good way to increase shareholder value.

I would like to thank Jim Stanford for his service on our Board from 1990 to 2000. Jim served as Chairman of the Board from January to May 2000, as part of his desire to ensure a smooth transition from being President and CEO. We are fortunate to have, as our new Chairman, Brian MacNeill, who has served on our Board since 1995 and whose deep experience includes 10 years as chief executive of Enbridge Inc. In addition, Bob McCaskill retired as Senior Vice-President at the end of March 2001. We thank him for his 23 years of service.

I am very excited about the future for Petro-Canada. We accomplished a great deal in 2000, but there is still much more potential to be realized. We have excellent assets, superb growth opportunities, financial strength, and a skilled, dedicated workforce. With renewed focus and discipline in execution, we can work diligently to build superior value for our shareholders.

R.A. Brenneman

Ron Brenneman
President and Chief Executive Officer

FINANCIAL AND OPERATING REVIEW

MANAGEMENT'S DISCUSSION & ANALYSIS

FINANCIAL STATEMENTS

MANAGEMENT'S DISCUSSION & ANALYSIS

The Management's Discussion & Analysis should be read in conjunction with the Financial Statements and Notes included in this report. Graphs accompanying the text identify our 'value drivers', key measures of performance in each component of our business.

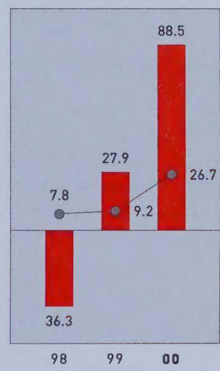
RESULTS OF OPERATIONS

Summarized Financial Results

Capitalizing on an exceptional business environment, Petro-Canada achieved record earnings in 2000. Highlights in the Upstream included strong oil and gas volumes, and excellent finding and development cost performance despite rising industry costs. Completion of a non-core asset divestiture program allowed us to sharpen our focus on more profitable business opportunities. In the Downstream, high refinery utilization and reliability enabled us to maximize production volumes and take advantage of strong refining margins. Some early benefit was also realized from a corporate reorganization and a critical examination of current expenditures, though it is expected that most of the gain from these cost reductions will be seen in the years ahead.

SHAREHOLDER VALUE

Shareholder value grew 88.5 per cent through market appreciation and higher dividends.



■ One-year return *(per cent)*

● Three-year average return *(per cent)*

- Shareholder value measures the change in the Petro-Canada share price plus dividend returns.

Consolidated Financial Results (millions of dollars, unless otherwise indicated)

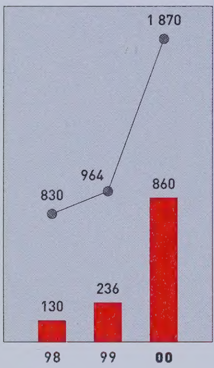
	2000	1999	1998
Earnings from operations before reorganization costs	**860**	236	130
Reorganization costs	**(38)**	—	(42)
Gain (loss) on sale of assets	**71**	(3)	7
Net earnings	**893**	233	95
Earnings per share (dollars) — basic	**3.28**	0.86	0.35
— fully diluted	**3.22**	0.86	0.35
Cash flow[1]	**1 870**	964	830
Cash flow per share (dollars)	**6.87**	3.55	3.06
Average capital employed	**5 884**	5 630	5 536
Return on capital employed (per cent)	**16.6**	5.6	3.0
Operating return on capital employed before reorganization costs (per cent)	**16.0**	5.6	3.6
Return on equity (per cent)	**21.0**	5.8	2.4
Debt	**1 774**	1 711	1 829
Cash and short-term investments	**1 415**	206	431

1 Before changes in non-cash working capital items.

The Management's Discussion & Analysis contains forward-looking statements, including, but not limited to, references to: future capital and other expenditures (including the amount, nature and sources of funding), oil and gas production levels and the sources of their growth, tax and royalty rates, oil and gas prices, the Canadian dollar exchange rate, interest rates, refining and marketing margins, demand for refined petroleum products, planned facilities construction and expansion, retail site throughputs, pre-production and operating costs, proved and probable reserves, natural gas export capacity, results of exploration and development activities, acquisition and disposition of resource properties, and the dates by which certain areas will be developed or will come on stream. These forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; refining and marketing margins; the ability to produce and transport crude oil and natural gas to markets; the results of exploration and development drilling and related activities; fluctuation in foreign currency exchange rates; the ability of suppliers to meet commitments; actions by governmental authorities including increases in taxes; changes in environmental and other regulations; risks attendant with oil and gas operations; and other factors, many of which are beyond the control of Petro-Canada.

OPERATING EARNINGS AND CASH FLOW

New records were established for cash flow and operating earnings.



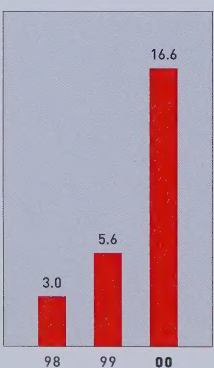
■ Earnings from operations *($ millions)*

● Cash flow *($ millions)*

– 1998 and 2000 earnings are before reorganization costs.

RETURN ON CAPITAL EMPLOYED

Higher earnings led to a strong improvement in return on capital employed.



■ Return on capital employed *(per cent)*

2000 Compared with 1999

Higher commodity prices, coupled with improved refining margins and strong volume performance, boosted net earnings to a record $893 million, up 283 per cent from $233 million in 1999. Cash flow almost doubled to a record $1 870 million. Reflecting the significant increase in earnings, return on capital employed rose to 16.6 per cent from 5.6 per cent in 1999. Year 2000 earnings reflect after-tax reorganization costs of $38 million, and a $71 million after-tax net gain on the sale of the natural gas liquids business, non-core oil and gas properties including interests in Norway, and other assets. Reorganization costs relate to a realignment of Downstream operations along functional lines, as well as staff reductions in Shared Services and the Upstream sector.

Effective January 1, 2000, Petro-Canada adopted the recommendations of the Canadian Institute of Chartered Accountants (CICA) on accounting for income taxes. This resulted in a reduction of income taxes and an increase in net earnings in 2000 of $30 million, reducing Petro-Canada's effective income tax rate to 39.1 per cent from 44.8 per cent in 1999. Since the accounting change was adopted retroactively, retained earnings as at January 1, 2000 have been reduced by $175 million and liability for future income taxes has been increased by the same amount. A CICA recommendation on accounting for employees' future benefits has also been adopted, prospectively, resulting in a reduction in net earnings of $3 million in 2000.

Earnings from operations before reorganization costs rose to $860 million in 2000 from $236 million in 1999. Upstream operating earnings, driven primarily by higher oil and gas prices, climbed to $704 million from $243 million. Strong production volumes, mainly from gains at Hibernia and in natural gas, were also key to the improved performance. Downstream operating earnings increased by $158 million to $273 million, reflecting higher refining margins and wider light/heavy crude oil price differentials. Net expenses from Shared Services declined to $117 million from $122 million.

Quarterly Financial Information

(See page 45 of the 2000 Annual Report for summarized 1999 and 2000 quarterly financial results.)

In the fourth quarter of 2000, operating earnings before reorganization costs of $5 million were $287 million, up from $74 million in the same period of 1999. Cash flow was $684 million compared with $315 million a year earlier. Petro-Canada recorded an after-tax gain of $104 million relating to the disposal of assets compared with a loss of $8 million in the fourth quarter of 1999.

Upstream earnings from operations in the fourth quarter of 2000 were $244 million, up significantly from $98 million during the same period of 1999, largely as a result of higher oil and gas prices. Downstream earnings from operations in the fourth quarter were $66 million, up from $9 million in 1999, due to higher refining margins and wider light/heavy crude oil price differentials. Marketing and lubricants margins remained depressed, primarily as a result of high feedstock costs.

Business Conditions

Petro-Canada's financial results are significantly influenced by crude oil and natural gas prices, refined product margins, light/heavy oil price differentials, the Canadian/U.S. dollar exchange rate, and demand for natural gas and refined petroleum products.

Business Conditions in 2000

The price of crude oil rose to exceptional heights in 2000. On the New York Mercantile Exchange (NYMEX), the price of benchmark West Texas Intermediate (WTI) oil averaged U.S.$30.20 per barrel (bbl), an increase of 56 per cent from the 1999 average of U.S.$19.30/bbl. At year-end 2000, WTI stood at U.S.$26.80/bbl. The move to higher prices began early in 1999, in response to OPEC's successful implementation of production cutbacks to eliminate an excess supply of crude oil from world markets. In 2000, prices continued to strengthen in response to increasing world demand, primarily from improving Asian economies. The impact of rising international oil prices on Canadian crude prices was amplified by continued weakness of the Canadian dollar relative to the U.S. currency. The Canadian dollar exchange rate averaged 67.40 U.S. cents, about the same as in 1999. Petro-Canada's posted prices for benchmark Edmonton Light crude oil averaged $44.75/bbl during 2000, up almost 62 per cent from 1999.

Natural gas prices across North America rose at an even more dramatic pace than prices for crude oil. Fired by increasing demand and uncertainties over near-term supply, the average NYMEX price for natural gas at the Henry Hub in Louisiana increased 72 per cent, to U.S.$3.91 per million British thermal units (MMBTU), from U.S.$2.27 in 1999. Following the early onslaught of severely cold winter weather across major consuming markets, the Henry Hub price peaked at a record U.S.$9.98/MMBTU on December 27. The Henry Hub — AECO-C differential, which averaged U.S.$0.28/MMBTU in 1999, was U.S.$0.54 in 2000. On December 1, 2000, start-up of the Alliance Pipeline provided Western Canadian producers with expanded access to U.S. gas markets. With throughput capacity of 1.3 billion cubic feet (bcf) of gas per day, this new pipeline from Alberta to Chicago substantially enhanced Canada's competitive supply status on the U.S. natural gas grid. Reflecting these developments, the average gas price at the AECO-C Hub in Alberta rose to $5.24 per thousand cubic feet (mcf), up 69 per cent from $3.09 in 1999.

Key factors affecting Downstream financial results are the level and volatility of crude oil prices, industry refining margins, movements in crude oil price differentials, demand for refined products, and the degree of market competition. In 2000, the industry enjoyed significant benefits from strong refining margins and wide light/heavy oil price differentials. The New York Harbor 3-2-1 crack spread, a benchmark indicator of the margin available to refiners, averaged U.S.$5.53/bbl, up 120 per cent compared with the average of U.S.$2.51/bbl in 1999. The crude oil price differential between benchmark North Sea Brent (light) and Mexican Maya (heavy) increased to U.S.$5.40/bbl from an average of U.S.$3.44/bbl in 1999. Based on Petro-Canada's posted prices, the average spread between Edmonton Light and Bow River (heavy) increased to $10.88/bbl, up 152 per cent from $4.32/bbl in 1999. An additional factor positively affecting the downstream sector in 2000 was a widening of the price differential between WTI and lower priced North Sea Brent, to U.S.$1.81/bbl from an average of U.S.$1.37/bbl in 1999.

Canadian refined petroleum product sales grew 1.8 per cent in 2000, compared with an increase of 1.0 per cent in 1999. The 2000 growth was led by sales of distillates, while retail sales of gasoline remained flat.

Outlook for Business Conditions in 2001

Prices for energy commodities are influenced by developments in supply and demand, weather, political events, and the level of industry inventories. In 2001, Petro-Canada expects continued volatility and uncertainty in oil prices. OPEC is currently maintaining considerable control over world supply, but should OPEC's discipline waiver or global oil demand weaken, international oil prices could quickly soften.

The rapid rise in natural gas prices experienced in 2000 could also be eroded in 2001 by softer demand, should the North American economy continue to weaken. Responding to the long-term prospect of strong growth in demand, the industry is directing increased attention to securing additional large sources of supply. In Canada, the major focus is on such proven gas-prone areas as the Mackenzie Delta and Scotian Shelf. Rising natural gas prices and advances in operational and development technology have significantly enhanced the economics of exploration and development in these regions. Success in these remote locations, however, will be contingent upon discovery of the necessary threshold reserves to justify installing the extensive and costly infrastructure required to bring new supplies to market.

Given the economic slowdown which is becoming evident across North America, little, if any, growth is anticipated in domestic sales of refined products in 2001. Margins on such products will depend on the movement in crude oil prices over the year, the level of refined product inventories, and competition in the marketplace.

Economic Sensitivities

The following table shows the estimated after-tax effects that changes in certain factors would have had on Petro-Canada's 2000 net earnings had these changes occurred. We base these calculations on business conditions, production and sales volumes realized in 2000.

Sensitivities Affecting Net Earnings

Factor	2000 average	Change (+/-)	Approximate Change (+/-) in Net Earnings[1] (millions of Canadian dollars)
Upstream Sector			
WTI benchmark crude oil price	U.S. $30.20/bbl	U.S. $1.00/bbl	21
Price received for natural gas	$4.75/mcf	$0.10/mcf	12
Production of crude oil and liquids	89 200 barrels per day (b/d)	1 000 b/d	3
Production of natural gas available for sale	738 million cubic feet per day (mmcf/d)	10 mmcf/d	2
Downstream Sector			
Downstream margin[2]	5.6 cents per litre	0.1 cent per litre	12
Light/heavy crude price differential[3]	$10.88/bbl	$1.00/bbl	14
Corporate			
Canadian dollar exchange rate ($U.S. per $Cdn.)[4]	U.S. $0.6740	U.S. $0.01	(6)

1 The impact of a change in one factor may be compounded or offset by changes in other factors. This table does not consider the impact of any interrelationship among the factors. The application of these factors may not necessarily lead to an accurate prediction of future results of operations. We may undertake risk management initiatives from time to time that affect these sensitivities.
2 Revenue minus cost of sales.
3 The spread between the prices of benchmark Edmonton Light and Bow River (heavy) crude oils.
4 A strengthening Canadian dollar versus the U.S. dollar has a negative effect on Petro-Canada's earnings.

Upstream Sector

Upstream Financial Results (millions of dollars, unless otherwise indicated)

	2000	1999	1998
Earnings from operations	**704**	243	29
Gain on sale of assets	**72**	6	30
Net earnings	**776**	249	59
Cash flow	**1 538**	885	516
Operating return on capital employed (per cent)	**22.4**	7.1	0.9
Cash flow return on capital employed (per cent)	**48.9**	25.9	15.7
Average capital employed	**3 146**	3 416	3 288

2000 Compared with 1999

Upstream earnings from operations rose to a record $704 million in 2000, up 190 per cent from 1999. Upstream cash flow increased 74 per cent to $1 538 million. Sharply higher oil and gas prices were the main drivers of the improved performance. Petro-Canada's average price received for crude oil and field natural gas liquids production, including the effects of hedging activities, was $41.45/bbl, up from $24.58 a year earlier. The average price received for natural gas was $4.75/mcf, up from $2.59 in 1999.

Total production in 2000 averaged 212 200 barrels of oil equivalent (BOE) per day, consisting of 89 200 barrels of oil and liquids and 738 million cubic feet of natural gas (converted at 6 000 cubic feet of gas to one barrel of oil equivalent). Production was marginally below the 215 100 BOE per day achieved in 1999, as increased oil production from Hibernia and higher natural gas volumes were more than offset by non-core property sales in Western Canada and lower Syncrude production.

Total proved plus probable reserves climbed eight per cent to 1 620 million BOE, largely due to the inclusion of 247 million barrels of probable reserves at Petro-Canada's new *in situ* oil sands development project at MacKay River, which more than offset the reserves associated with property dispositions. Independent reservoir engineering consultants conduct annual technical audits of one-third of Petro-Canada's proved conventional oil and natural gas reserves on a rotational basis. In addition, Arthur Andersen LLP, as contract auditor, tests on an annual basis non-engineering management control processes we use in establishing reserves.

Upstream Review & Outlook

Petro-Canada's core Upstream businesses include East Coast offshore, oil sands, and natural gas, complemented by modest oil production in Western Canada and Algeria. A strong balance sheet and substantial cash flow enables us to maximize development of core assets, while aggressively pursuing new growth prospects. Petro-Canada's growth profile is heavily weighted toward increasing crude oil production from the Grand Banks, offshore Newfoundland, and growing oil sands production from northern Alberta.

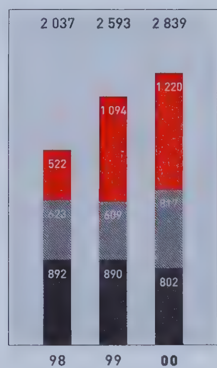
OIL AND GAS PRODUCTION

Production was down slightly in 2000 due to asset sales.

■ Upstream production *(thousands of barrels of oil equivalent per day)*

RESERVES INVENTORY

Our large reserves inventory provides a strong base for future growth.



■ Proved reserves *(millions of barrels of oil equivalent)*

■ Probable reserves *(millions of barrels of oil equivalent)*

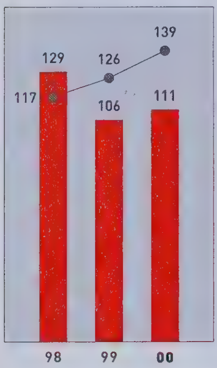
■ Possible reserves *(millions of barrels of oil equivalent)*

(Caution should be exercised in aggregating proved, probable and possible reserves. There is a 90% probability that actual reserves will equal or exceed proved reserves, a 50% probability that actual reserves will equal or exceed the sum of proved and probable reserves and a 10% probability that actual reserves will equal or exceed the sum of proved, probable and possible reserves.)

– In the above graphs, 1998 and 1999 numbers have been restated to reflect a change in the gas-to-oil conversion factor, from 10:1 to 6:1.

RESERVE REPLACEMENT

We again more than replaced production with new reserves.



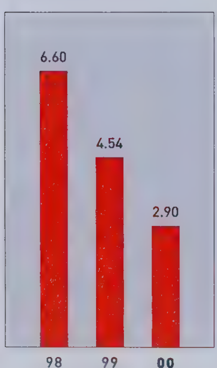
■ Natural gas *(per cent)*

● Total conventional oil and gas *(per cent)*

- Excludes acquisitions and divestitures
- Excludes Syncrude
- 1998 and 1999 numbers have been restated to reflect a change in the gas-to-oil conversion factor, from 10:1 to 6:1.

HIBERNIA OPERATING AND OVERHEAD COSTS

Operating and overhead costs per barrel continued to decline.



■ Unit operating and overhead costs *($ per barrel)*

On the Grand Banks, Petro-Canada has a 20 per cent share in the producing Hibernia field, is operator of the Terra Nova development which is expected to come on stream late in 2001, and is a working-interest participant in all other oil discoveries made to date. In 2000, we further consolidated our position in this highly prospective region by increasing our working interests at Terra Nova (to 34.0 per cent) and White Rose (to 27.5 per cent) through a property swap. The next two years should see strong production growth from the Grand Banks as Terra Nova comes on stream and Hibernia achieves peak production. Petro-Canada and our partners are also pursuing plans for development of the White Rose and Hebron/Ben Nevis oil fields. Elsewhere in this offshore region, we are accelerating longer term exploration, particularly in the Flemish Pass and Salar basins and on the Scotian Shelf, offshore Nova Scotia.

Petro-Canada is a leading participant in the development of northern Alberta's vast oil sands resources. We have a 12 per cent share of Syncrude, the world's largest oil sands mining operation, and significant interests in other leases where there is potential to extract bitumen *in situ* (or, in place) using leading-edge technology. Ongoing expansion of Syncrude, together with development of our first commercial *in situ* operation at MacKay River (in which we hold 100 per cent working interest), will provide major production growth for Petro-Canada over the next several years.

Petro-Canada is one of the largest producers of natural gas in Western Canada, where we continue to invest with considerable success, particularly in the Alberta Foothills. For longer-term growth, we are aggressively evaluating recently acquired acreage in the Mackenzie Delta region of the Northwest Territories. The Geological Survey of Canada estimates the potential of the Mackenzie Delta to be in the range of 20 trillion cubic feet of recoverable natural gas. About six trillion cubic feet of proven gas has been discovered by industry to date, which may be sufficient to justify pipeline construction to the North American transportation grid.

East Coast Offshore

Petro-Canada's share of Hibernia production averaged 28 900 barrels per day (b/d) in 2000, up from 20 000 b/d the previous year. The consistently strong production was achieved despite a scheduled 12-day maintenance shutdown of the production platform. As a result of Hibernia's production growth, unit operating costs declined to $2.76/bbl in 2000 from $4.23/bbl in 1999 and are projected to fall further. At year end, Petro-Canada's share of Hibernia's remaining proved plus probable reserves was estimated at 123 million barrels.

During 2000, the first producing well and a water injector were drilled in the Avalon sands, which lie above the Hibernia formation. The Avalon sands are believed to contain more oil than the Hibernia sands but, due to highly faulted and complex geology, recovery is more difficult. At year end, 10 producing oil wells, six water injectors, and three gas injectors were in operation in the Hibernia field. Drilling was in progress on two new producers, one in each of the Hibernia and Avalon sands.

Responding to Hibernia's excellent reservoir and operating performance, the owners and the government of Newfoundland and Labrador agreed in 2000 to realign the royalty regime to allow the platform to produce to its practical limits. The actual rate of production will depend upon field performance and the pace of future drilling. Currently, the reservoir is experiencing higher-than-expected gas to oil ratios which, combined with platform compressor limits, is constraining oil production. These oil production limits are expected to be resolved by 2003, when additional gas injection areas are developed and more wells become available. While Petro-Canada's share of Hibernia production in 2001 is expected to to be similar to the past year's volume, the development program continues to focus on achieving and maintaining target field production of 160 000 b/d (32 000 b/d net to Petro-Canada) over the next several years.

Another milestone in Canadian offshore activity will be reached in 2001, when the Terra Nova oil field, the first Petro-Canada operated Grand Banks development, is placed on production. The highlight in 2000 was safe delivery of the floating production, storage and offloading vessel from a shipyard in South Korea to Bull Arm, Newfoundland. Following installation of production modules, the vessel is undergoing onshore commissioning and testing. Field activity during 2000 included drilling and completion of three wells along with installation of production flowlines to link the wells with the vessel. In 2001, five development wells are planned on the two initial development blocks, the Graben and East Flank, and we expect to drill and evaluate one delineation well on the Far East block.

The start of Terra Nova oil production has been extended from the second quarter to the fourth quarter of 2001, to address design and engineering workmanship problems identified in several key systems of the production vessel after its arrival in Bull Arm. Total project pre-production capital costs have not been finalized, but Petro-Canada expects the number could increase by up to 15 per cent over the current estimate of $2.5 billion. Despite the delay and the cost overrun, the project remains an attractive investment for Petro-Canada.

At full rates, annual production is expected to average 129 000 b/d, or 43 800 b/d net to Petro-Canada. Terra Nova will require only 24 production and injector wells, compared with the eventual 80-plus wells needed at Hibernia. Gross reserves on the Graben and Far East blocks, estimated by Petro-Canada at 370 million barrels, are expected to be produced over 12 to 14 years, while additional reserves are possible from the adjacent Far East block.

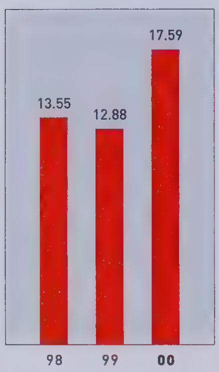
Elsewhere on the East Coast, delineation wells were drilled at White Rose and Hebron/Ben Nevis to further define the extent of earlier discoveries. Early in 2001, Petro-Canada and project operator Husky Oil Operations Ltd. filed a development application with the Canada-Newfoundland Offshore Petroleum Board for the White Rose field. This filing does not constitute a decision to proceed with development, as engineering studies and cost estimates have yet to be completed. White Rose is estimated to contain between 200 and 250 million barrels of light crude oil. The commercial prospects of the Hebron/Ben Nevis discoveries (where Petro-Canada has a 23.9 per cent working interest) continue to be evaluated. Other 2000 drilling in the Jeanne d'Arc Basin included exploratory wells at Cape Race and Riverhead, but neither encountered hydrocarbons in commercial quantities.

Expanding our offshore focus, we have begun to evaluate unexplored or lightly explored basins in deeper waters beyond the Jeanne d'Arc Basin. Petro-Canada's deep-water prospects are located in less than 1 500 metres of water, making them quite manageable with today's technology. Our 2000 program included initial evaluation of exploration prospects in the Flemish Pass, east of the Grand Banks. Petro-Canada's ownership interests in this region total 1.64 million gross (0.74 million net) acres. A 4 200-square kilometre 3-D seismic program completed in 2000 is currently being processed. We are considering drilling on these lands as early as 2002. Late in 2000, we expanded our inventory of deep-water prospects with the acquisition of a 50 per cent interest in a 466 000-acre block in the unexplored Salar Basin, southeast of the Grand Banks.

Offshore Nova Scotia, we are evaluating the development potential of deep-water natural gas prospects on the Scotian Shelf. Petro-Canada holds a 35 per cent interest in 419 000 gross acres in the region and has entered into a farm-in agreement to secure a 67 per cent interest in an adjoining 742 000-acre block. Evaluation is underway on 2 000 square kilometres of 3-D seismic shot in 2000. Favourable prospect definition could lead to drilling as early as 2002. An attraction of the Scotian Shelf play is its proximity to the northeastern U.S. market.

SYNCRUDE OPERATING AND OVERHEAD COSTS

Operating and overhead costs increased due to operational problems and higher gas prices.



Unit operating and overhead costs *($ per barrel)*

Oil Sands

Early in 2000, Petro-Canada established oil sands as a core business, based on the development potential of our extensive *in situ* oil sands properties and our ownership position in Syncrude.

In 2000, Syncrude continued to be a strong earnings contributor to Petro-Canada. The strong performance reflected the impact of high oil prices, partially offset by reduced production. Petro-Canada's share of Syncrude production in 2000 averaged 24 300 b/d, down from 26 700 b/d in 1999. The volume decline resulted from operational difficulties associated with the start-up of new units, longer-than-planned maintenance shutdowns, and the advancement of an upgrading unit turnaround from 2001 to the third quarter of 2000.

Unit operating costs at Syncrude increased to $17.53/bbl in 2000 due to reduced throughput, extensive maintenance, and increased fuel costs. In 2001, Petro-Canada's share of Syncrude production is expected to increase to about 30 000 b/d with expectations of much-improved plant reliability.

Petro-Canada's share of Syncrude capital expenditures was $61 million in 2000, down from $90 million in 1999, reflecting the conclusion of the second stage of expansion. Highlights in 2000 included the mid-year start-up of Train 1 at the Aurora mine and completion of an upgrader debottleneck, which are expected to increase yield and reduce emissions. Further development of the Aurora mine and an additional upgrader expansion are being evaluated, with a decision expected in mid-2001. This next expansion is expected to increase Petro-Canada's share of Syncrude production to about 40 000 b/d by the end of 2004. Further expansion would raise our share of production to more than 50 000 b/d by the end of 2007.

In September, Petro-Canada announced a strategy for the phased development of our extensive *in situ* oil sands prospects, with the potential for integration with our Edmonton refinery. Petro-Canada has interests in more than 200 000 net acres of oil sands leases considered prospective for *in situ* development. Bitumen is extracted *in situ* where oil sands are too deep to be mined economically from the surface. Petro-Canada will use steam-assisted gravity drainage to extract the bitumen, with less surface disruption than in traditional mining operations. This technology, proven through pilot and commercial-scale testing over the past 15 years, can economically recover more than 60 per cent of the oil in place using horizontal well pairs. Low-pressure steam is injected through the upper well, mobilizing the bitumen, which drains into the lower production well.

As a first step, following regulatory approval, we began commercial development of our MacKay River acreage, including construction of a bitumen production facility which we expect to bring on stream in late 2002. We have applied to the Alberta Energy and Utilities Board for approval to increase the facility's production capacity from 22 000 to 33 000 b/d. We expect this property to produce an average of 30 000 b/d for 25 years. Bitumen production will be transported via a short lateral pipeline, being built by Enbridge Inc. to connect with existing pipelines, thereby securing access to North American crude oil markets. Start-up capital expenditures for the MacKay River development are planned at $290 million.

We plan to use our experience at MacKay River in further *in situ* oil sands developments. In the winter of 2000-2001, we are conducting seismic and delineation drilling on two prospective properties, Lewis and Meadow Creek, to determine the extent of the resource and the potential for development.

For the long term, we are evaluating the potential of an integrated oil sands development, which would link production of *in situ* bitumen around Fort McMurray with processing at our first-quartile Edmonton refinery. In 2001, Petro-Canada will begin stakeholder consultations concerning future *in situ* development and feedstock conversion at the Edmonton refinery.

Western Canada Natural Gas

Natural gas production in 2000 averaged 738 mmcf/d, up from 719 mmcf/d in 1999 despite the sale of non-core properties. Major production gains in the Alberta Foothills and the deferral of gas plant maintenance shutdowns, to capitalize on the high-price environment, were key contributors to the improved performance.

Sales of two additional non-core properties were in progress at year end. The Whitecourt sale closed in February 2001 and the Kaybob sale is expected to close in the first half of 2001. As a result of non-core property dispositions and planned gas plant maintenance shutdowns, natural gas volumes in 2001 are expected to average about 680 mmcf/d.

The average natural gas price realized by Petro-Canada in 2000 was $4.75/mcf, up 83 per cent from $2.59/mcf in 1999. Operating costs declined to $0.44 per thousand cubic feet of gas equivalent (mcfe) from $0.47/mcfe, reflecting implementation of cost initiatives and the initial effects of the disposition of higher cost, non-core properties.

Exploration and development success in 2000 added 301 bcf of natural gas to proved reserves, enabling us to replace 111 per cent of current year production. Due to the net sale of producing properties, however, total proved gas reserves in Western Canada declined from 2 472 to 2 331 bcf. Our three-year average finding and development cost for natural gas was $0.99/mcfe, an excellent performance in the current environment of high land, drilling and service costs. In an effort to achieve and maintain strong and profitable growth, we are targeting consistent top-quartile performance in all controllable measures, particularly with respect to finding and development costs.

Conventional crude oil and natural gas liquids production averaged 23 400 b/d in 2000, down from 36 400 b/d in 1999. Asset sales, arising from Petro-Canada's planned exit from conventional oil production in Western Canada, accounted for 12 600 b/d of the decline. Ferrier and Willesden Green, oil properties which are integrated with our west-central Alberta gas infrastructure, are being retained as core assets. Western Canada conventional oil and natural gas liquids production was 19 000 b/d at year-end 2000.

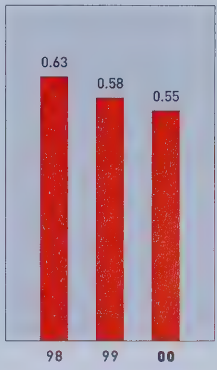
Capital expenditures for exploration and development in Western Canada in 2001 are budgeted at $380 million. Through this substantial capital program, we expect to replace 2001 production with new reserves. Plans include drilling about 50 exploration and development wells in the Alberta Foothills and 25 in northeastern British Columbia, as well as other drilling in west-central and southeastern Alberta.

Exploration and development activity in Western Canada continues to focus primarily on natural gas prospects in the Alberta Foothills, an extensive area characterized by larger pools and lower decline rates than in other parts of the Western Canada Sedimentary Basin. Through aggressive capital investments, we have realized substantial growth in reserves and production in this region. Capital expenditures allocated to the Alberta Foothills have risen from about $100 million in 1997, to $235 million in 2000. Over this period, we have added more than 730 billion cubic feet of gas equivalent (bcfe) to reserves at an average finding and development cost of $0.86/mcfe. Foothills gas production has grown from an average of 210 mmcf/d in 1996 to 350 mmcf/d in December 2000, and now represents about 50 per cent of Petro-Canada's total natural gas volumes.

In 2000, about 62 per cent of our capital expenditures on conventional oil and gas in Western Canada were allocated to the Alberta Foothills program. Most of these expenditures targeted new drilling opportunities in the Wildcat Hills and Hanlan areas. At Wildcat Hills, where multi-year drilling successes have been achieved in developing production from the Turner Valley formation, we have begun to develop sweet gas from the Viking formation. Production from Wildcat Hills in December 2000 averaged 139 mmcf/d, up 40 per cent from 99 mmcf/d at the previous year's end. Through successful drilling in the Hanlan area, we more than offset natural field decline, raising average production to 111 mmcf/d in December 2000, up from 104 mmcf/d in December 1999.

WESTERN CANADA OPERATING AND OVERHEAD COSTS

Costs per unit continued to decline.

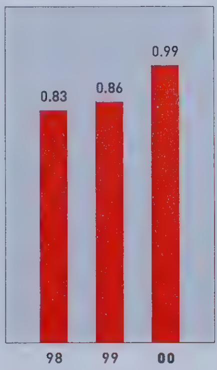


■ Unit operating and overhead costs *($ per thousand cubic feet of gas equivalent)*

- Includes Western Canada gas, conventional oil and liquids

NATURAL GAS FINDING AND DEVELOPMENT COSTS

Finding and development costs remained competitive despite rising service and supply costs.



■ Natural gas *($ per thousand cubic feet of gas equivalent)*

- Three-year rolling average for proved reserves
- Excludes acquisitions and divestitures

In northeastern British Columbia, following a comprehensive technical analysis of our holdings, we sold a number of properties that had been reclassified as non-core. The analysis also served to expand our prospect inventory. Selective drilling in the region in 2000 was rewarded with a high level of success, notably at Jedney, where four exploration and six development wells provided 22 mmcf/d of new gas production, while adding 37 bcf of gas to reserves. About 10 wells are planned for this area in 2001.

Mackenzie Delta

In 2000, we added to our holdings in the Mackenzie Delta with the acquisition of two new exploration licences and two Inuvialuit land concessions, one of which contains an existing natural gas discovery. With interests in six blocks, covering about one million gross (0.6 million net) acres, Petro-Canada is now one of the largest leaseholders in this high-risk but high-potential exploration play. An initial seismic shoot across the original two blocks early in 2000 identified several prospects on acreage acquired in 1999. We are shooting additional 3-D and 2-D seismic on our acreage over the 2000-2001 winter season. In February 2001, Petro-Canada began drilling the first natural gas exploration well in the Mackenzie Delta in more than a decade. The well, on the Kurk block in which Petro-Canada has a 60 per cent interest, will be drilled to a depth of 2 500 metres. Drilling is expected to be completed by April.

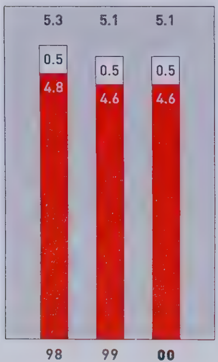
International

During 2000, Petro-Canada identified our oil-producing properties in Norway as non-core and sold these assets for U.S.$76 million. Petro-Canada's share of production from these properties averaged 8 900 b/d in 2000, up from 7 700 b/d in 1999.

Our remaining international interests are in Algeria, where we hold a 70 per cent interest in the Tamadanet oil field, and in south-central Tunisia, where we have exclusive rights to explore in the Tataouine block. Our share of production from the Tamadanet field, before royalty and the sharing of profit oil, averaged 3 700 b/d in 2000, down from 4 500 b/d in 1999, due to natural decline. Early in 2001, negotiations with the Algerian state oil company concerning a potential regional gas development were suspended. As a result, we are re-evaluating our future strategy in North Africa.

DOWNSTREAM OPERATING AND OVERHEAD COSTS

Per-litre costs remained steady in 2000 despite inflationary pressures.



Unit operating costs *(cents per litre)*

Unit overhead costs *(cents per litre)*

Downstream Sector

Downstream Financial Results (millions of dollars, unless otherwise indicated)

	2000	1999	1998
Earnings from operations	**273**	115	204
Loss on sale of assets	**(1)**	(9)	(35)
Net earnings	**272**	106	169
Cash flow	**434**	163	420
Operating return on capital employed (per cent)	**13.0**	5.7	10.3
Average capital employed	**2 104**	2 021	1 981

2000 Compared with 1999

Petro-Canada achieved record Downstream earnings and a substantial increase in cash flow in 2000, despite weak economic conditions for sales and marketing. High crack margins and wide light/heavy crude oil price differentials were key elements of an improved refining environment. A strong light/heavy price differential is advantageous to Petro-Canada as our refineries in Ontario and Quebec can process a high percentage of heavy crude, thereby lowering feedstock costs. Sharply higher natural gas fuel costs were a partially offsetting factor. Downstream unit operating and overhead costs were maintained at 5.1 cents per litre in 2000.

In 2000, initiatives to capitalize on a favourable business environment enabled our refineries to run three per cent more crude than in 1999, through improved conversion unit reliability and the deferral of planned maintenance shutdowns at Oakville and Montreal. With record asphalt sales of 1.5 billion litres, we were able to run a heavier crude slate and take advantage of the strong light/heavy spreads. Sales of refined petroleum products were up eight per cent to 55 400 cubic metres per day (m^3/d), compared with 51 200 m^3/d in 1999. The largest gains were achieved in wholesale and refinery sales channels.

In contrast to the excellent results from refining operations, the contribution to earnings and cash flow from marketing and lubricants in 2000 was weak, as the high and rising cost of refined products and lubricants feedstock could not be fully recovered in the marketplace.

Downstream Review & Outlook

Petro-Canada's Downstream operations consist of refineries in Edmonton, Oakville and Montreal, a lubricants manufacturing plant in Mississauga, and a nationwide network of retail and wholesale outlets. Over the past several years, a significant operational effort has focused on positioning the Petro-Canada brand for competitive success in both the retail and wholesale markets.

In 2000, to advance the drive to first-quartile cost performance and consistently strong financial results, we restructured Downstream operations along functional rather than regional lines. The national alignment of marketing programs is a key benefit of this initiative.

Refining and Supply

Exceptional performance by our refining business in 2000 resulted in record earnings from operations. These results were driven by strong crack margins and high levels of refinery reliability and capacity utilization.

Responding to sustained high throughput at the Edmonton refinery, the facility's rated capacity was increased to 19 900 m^3/d from 19 100 m^3/d. As a result, total capacity at Petro-Canada's three refineries has increased from 49 000 m^3/d to 49 800 m^3/d. Including this capacity increase, our refineries achieved 101 per cent crude capacity utilization in 2000. Other significant achievements included sustained high conversion unit reliability of over 90 per cent at Petro-Canada's three refineries and our lubricants plant.

The Canadian government's new regulation limiting levels of sulphur in gasoline presents a challenge to refiners over the medium term. The regulation requires sulphur to be reduced to an average of 150 parts per million (ppm) between mid-2002 and the end of 2004, with a further reduction to 30 ppm by 2005. We plan to begin refinery modifications in 2001 and continue to evaluate potential technology and operating solutions to help minimize supply disruptions and capital expenditures required to achieve the 2005 target.

In concert with the phased development of our *in situ* oil sands properties, Petro-Canada is evaluating the potential reconfiguration of the Edmonton refinery to process 12 720 to 23 850 m^3/d (80 000 to 150 000 b/d) of bitumen, replacing light crude oil as its primary feedstock. Conversion of the Edmonton refinery over the coming decade would provide Petro-Canada with a fully integrated bitumen production and refining operation in Alberta, with assured supply and the ability to create value at every step — from wellhead to finished product. Gasoline desulphurization modifications at our Edmonton refinery will be compatible with potential feedstock conversion investments.

In addition to projects required to meet the sulphur-in-gasoline regulation, the Refining & Supply business unit will focus on maximizing refinery utilization and reliability, and achieving first-quartile cost performance.

Most of the collective agreements covering about 1 200 unionized employees at our lubricants plant, three refineries, three terminals, and three Upstream gas plants expired in the first quarter of 2001. As of March 1, negotiations aimed at renewing the agreements were continuing.

REFINERY UTILIZATION

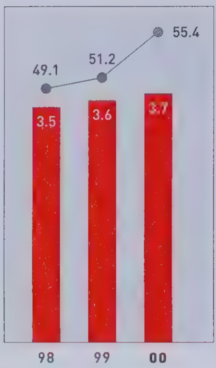
Refineries continued to run at full capacity in 2000.

■ Crude capacity utilization *(per cent)*

– Our rated refinery crude capacity was increased in 2000, following process improvements. The 1998 and 1999 figures are based on the lower rated capacity.

PRODUCT SALES

Total Downstream sales increased by 8 per cent in 2000, and sales per retail site also grew.



Retail throughput per site *(millions of litres per year)*

Petroleum product sales *(thousands of cubic metres per day)*

Sales and Marketing

Petro-Canada enjoys outstanding brand recognition as "Canada's Gas Station". Our clean gasoline blend, *SuperClean*, together with *WinterGas* and other products targeting Canada's unique driving conditions, continued to achieve strong market response in 2000. Petro-Points, our branded customer loyalty program, also continued to expand, engaging about five-million Canadian households by year end.

Petro-Canada's retail network consists of 1 618 sites, of which 883 are company-controlled. Average throughput per site in 2000 increased to 3.7 million litres, up from 3.6 million litres in 1999. During 2000, we accelerated the redevelopment of retail sites to Petro-Canada's new-image design. With annual throughputs averaging in excess of seven-million litres, the new-design sites have demonstrated a market advantage in increasing gasoline sales. By year end, 35 per cent of company-controlled outlets had been converted. In 2001, we will continue to capitalize on national marketing programs with the accelerated roll-out of new-image sites in key markets.

In addition to increasing gasoline sales, the focus of the retail redevelopment program is on expanding non-petroleum revenue and increasing earnings in any business environment. In 2000, Petro-Canada increased sales of non-petroleum products and services by 11 per cent. Convenience store sales rose in response to network growth and expanded sales offerings. Car wash sales increased as the result of further improvements in wash quality, automation and convenience.

At the wholesale level, strong resource and transportation sectors during 2000 continued to drive increased throughputs for both our Petro-Pass and associate channels. Petro-Pass sales increased by 13 per cent, as we expanded our national cardlock network to 206 sites. In total, our wholesale network consists of 316 sites. With the focus on continued growth, our plans include further improvements in ancillary products and services to more fully meet the needs of the trucking market and maintain our best-in-class status in the wholesale channel.

Lubricants

Petro-Canada is the largest producer of lubricant base stocks in Canada and one of the largest producers of pharmaceutical and food-grade white oils in the world. Manufacturing capabilities include premium quality lubricants for high-end industrial applications and next-generation engine oils.

In 2000, results from lubricants operations were seriously impacted by high feedstock and fuel costs resulting from the rise in oil and gas prices. Despite this setback, significant progress was made in repositioning the business for improved future performance. Total lubricant sales volume increased to 763 million litres. High-margin sales volumes, which rose about 10 per cent, accounted for almost half of total volumes sold. High-grading the product mix, to capture Petro-Canada's competitive advantage in producing high-value products, together with process improvements and plant reliability, are key to achieving long-term profitable growth in this business. New product line achievements in 2000 included the successful penetration of three new markets for premium lubricant and process oil applications. These were the launches of Luminol electrical transformer fluid, Duron Synthetic heavy duty engine oil and PureDrill, a unique process oil being used in drilling mud through a U.S. alliance.

Priorities in 2001 include achieving further increases in sales of high-value, niche-market products, as well as a continued emphasis on cost reduction. Closing the gap on key industry performance measures will be the prime focus of the lubricants operation. A big step in this direction in 2000 was the successful completion of a major maintenance shutdown of the white oils plant. Capital spending at our lubricants plant in 2001 will be limited to the maintenance of refinery and manufacturing operations.

Shared Services

Shared Services Financial Results (millions of dollars)

	2000	1999	1998
Net expenses before reorganization costs	**(117)**	(122)	(103)
Gain on sale of assets	**—**	—	12
Net expenses	**(117)**	(122)	(91)
Cash flow before reorganization costs	**(67)**	(84)	(68)

2000 Compared with 1999

Shared Services is structured as a cost centre that includes interest expense, general corporate revenues and expenditures, and investment income. The decline in net expenses in 2000 reflects an increase in investment income, partially offset by higher depreciation, depletion and amortization expense.

LIQUIDITY AND CAPITAL RESOURCES

Summary of Cash Flows (millions of dollars)

	2000	1999	1998
Net cash inflows (outflows) before change in operating working capital:			
Cash flow	**1 870**	964	830
Investing activities	**(489)**	(945)	(628)
Financing activities and dividends	**(214)**	(89)	(84)
	1 167	(70)	118
Decrease (increase) in operating working capital and other	**42**	(155)	238
Increase (decrease) in cash and short-term investments	**1 209**	(225)	356

Operating Activities

Cash flow rose 94 per cent to $1 870 million in 2000, reflecting higher earnings, partially offset by higher current taxes. The net deferral of about $300 million in current income taxes, most of which relates to earnings in the Petro-Canada Oil and Gas partnership, also contributed to the increase in cash flow. This compares to a net deferral of $100 million in 1999. In the Downstream, the inventory accounting method required for income tax purposes resulted in an increase in current income taxes of $53 million, compared with an increase in current income taxes of $141 million in 1999.

The net decrease of $42 million in working capital was due mainly to increases in accounts payable and accrued liabilities and income taxes payable, with a partial offset from a rise in accounts receivable. The increased levels of accounts payable and accounts receivable reflect the rise in prices for crude oil and natural gas.

Investing Activities

Capital and Exploration Expenditures (millions of dollars)

	2000	1999	1998
Upstream [1]			
Western Canada oil and gas exploration and development	**371**	276	361
Hibernia and Terra Nova	**282**	283	225
Other East Coast Offshore	**75**	42	20
Syncrude and other oil sands	**110**	107	70
Mackenzie Delta	**34**	—	—
International	**43**	47	72
Property acquisitions	**1**	22	43
Other	**11**	16	27
	927	793	818
Downstream			
Refining and supply	**102**	110	125
Marketing	**143**	90	133
Lubricants	**19**	20	15
Other	**—**	—	3
	264	220	276
Shared Services	**12**	8	22
Total property, plant and equipment and exploration	**1 203**	1 021	1 116
Deferred charges and other assets	**8**	5	17
Total	**1 211**	1 026	1 133

1 Includes exploration expenses of $171 million in 2000, $78 million in 1999 and $95 million in 1998.

2000 Compared with 1999

Petro-Canada's capital expenditures rose 18 per cent to $1 211 million in 2000. In the Upstream, where expenditures totaled $927 million, increased spending reflected aggressive exploration and development programs for natural gas in Western Canada, expanded full-cycle exploration offshore Canada's East Coast, and new investment on gas exploration in the Mackenzie Delta. Downstream expenditures increased to $264 million, mainly due to the accelerated development of new-image retail sites.

The sharpening of Petro-Canada's focus on its core businesses in 2000 resulted in proceeds of $722 million from the sale of non-core assets. Petro-Canada also acquired additional interests in the Terra Nova and White Rose projects through a property swap.

2001 Capital Budget

Petro-Canada's capital expenditure budget for 2001, including the Terra Nova increase discussed on page 13, is $1.5 billion, up 25 per cent from expenditures of $1.2 billion in 2000. This program will allow us to develop the full potential of opportunities arising from our assets. About $1.1 billion of 2001 expenditures is budgeted for Upstream activities, $400 million in the Downstream, and $20 million for corporate and other purposes.

Natural gas exploration and development will continue to receive substantial funding, with $380 million allocated to investment prospects in Western Canada and $55 million to gas exploration in the Mackenzie Delta. In oil sands, about $110 million is committed to the ongoing Syncrude expansion and $220 million to the construction of production facilities for oil sands development at MacKay River and delineation activities related to other *in situ* opportunities. Offshore Canada's East Coast, we plan to invest about $200 million on Terra Nova development, $40 million at Hibernia, and $50 million on other potential developments.

Downstream expenditures in 2001 will be directed toward accelerating the roll-out of our new-image retail gas stations and investments to comply with future sulphur-in-gasoline regulations.

Financing Activities and Dividends

Sources of Capital Employed (millions of dollars)

	2000	1999	1998
Long-term debt, including current portion	**1 774**	1 711	1 829
Shareholders' equity	**4 591**	4 083	3 936
	6 365	5 794	5 765
Foreign currency translation adjustment on long-term debt[1]	**(130)**	(87)	(212)
Total	**6 235**	5 707	5 553

1 The translation adjustment on long-term debt is amortized over the remaining term of the debt. The weighted average term of the debt was 18 years at December 31, 2000.

Petro-Canada has established leverage targets to ensure continued balance sheet strength and financial flexibility. Target ratios include debt to cash flow of 2.0 times and debt to debt plus equity of 30 per cent. In 2000, as a result of our strong financial performance, these ratios were 0.9 times and 27.9 per cent, respectively.

Total debt, including the $454-million current portion, was up $63 million from 1999 year end, primarily due to the weaker Canadian/U.S. dollar exchange rate on debt denominated in U.S. dollars.

Petro-Canada reviews its dividend strategy from time to time to ensure the alignment of dividend policy with shareholder expectations and our financial and growth objectives. In 2000, Petro-Canada paid $109 million in dividends, compared with $92 million in 1999. The current quarterly dividend is $0.10 per share.

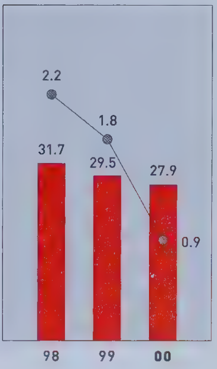
Petro-Canada will continue to use its cash position, and the issuance of short-term debt if necessary, to meet working capital and bridge financing requirements. For operating purposes, Petro-Canada has access to bank lines of credit and a commercial paper program totaling $1 175 million, supported by committed and demand credit facilities from several major Canadian financial institutions. As of December 31, 2000, the commercial paper program was not utilized as our cash and short-term investments were $1 415 million.

Effective November 1, 2000, The Toronto Stock Exchange approved Petro-Canada's application to make a Normal Course Issuer Bid for the repurchase of up to 22 million of its common and variable voting shares (about 10 per cent of its public float) over the 12-month period ending October 31, 2001. By year-end 2000, Petro-Canada had repurchased about four million shares at a cost of $134 million, or an average price of $33.91 per share. The repurchased shares have been cancelled. The Government of Canada, which owns 49.4 million Petro-Canada shares, is not participating in this Normal Course Issuer Bid. Given the strength of Petro-Canada's cash position, the share repurchase program is an effective means of adding value for shareholders while retaining the financial flexibility and resources to fund all major project commitments.

In February 2001, the federal government placed before Parliament a bill to eliminate the 25 per cent restriction on foreign ownership of Petro-Canada's stock and increase the limit on individual ownership from 10 to 20 per cent. Once passed into law, this legislation will provide Petro-Canada with improved competitive access to capital markets, leveling the playing field for all investors.

KEY DEBT RATIOS

Balance sheet strength is reflected in conservative debt ratios.

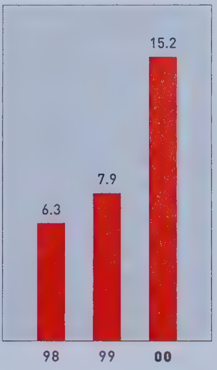


■ Debt to debt plus equity *(per cent)*

● Debt to cash flow *(times)*

INTEREST COVERAGE

A positive interest coverage ratio demonstrates more than sufficient earnings to cover interest charges on debt.



■ Interest coverage ratio *(times)*

– Calculated on an EBITDAX basis

Financial Ratios

	2000	1999	1998
Current ratio	**1.4**	1.2	1.4
Interest coverage (times)			
— earnings basis	**10.3**	3.7	2.2
— EBITDAX basis	**15.2**	7.9	6.3
— cash flow basis	**15.2**	8.2	6.7
Debt to cash flow (times)	**0.9**	1.8	2.2
Debt to debt plus equity (per cent)	**27.9**	29.5	31.7

RISK MANAGEMENT

Petro-Canada's risk management activities are conducted according to policies and guidelines established by the Board of Directors. Hedging, insurance and other techniques are used.

Our risk management policy prohibits the use of derivative instruments for speculative purposes. Petro-Canada uses derivatives primarily to hedge physical transactions for operational needs and to facilitate sales to customers. Commodity prices and margins may be hedged occasionally to capture opportunities that represent extraordinary value. Except as specifically authorized by the Board, the term of hedging instruments cannot exceed 18 months. We transact derivatives with counterparties who possess a minimum long-term credit rating of A (unless otherwise approved by the Board) under a signed International Swap Dealers Association agreement. Credit limits take into account current and potential exposure to losses due to non-performance of a counterparty and reduce credit risk concentration with any single counterparty. Monitoring and reporting of the derivatives portfolio includes periodic testing of the fair value of all outstanding derivatives. The net effect of commodity and currency hedging during 2000 increased earnings by about $1 million after tax. No interest rate hedges were implemented.

As of December 31, 2000, crude oil, heating oil and natural gas contracts had been bought forward to mitigate exposure on fixed-price natural gas and refined product sales. Short-term hedge positions were also in place for refining supply and product purchases. Petro-Canada has future commitments to sell and transport natural gas associated with normal operations. About eight per cent of our estimated 2001 natural gas production is sold under future fixed-price commitments at an average plant gate netback price of $2.51/mcf.

Petro-Canada manages operational risk through comprehensive risk assessment and loss management processes, and maintains adequate insurance coverage. We place insurance coverage globally, with financially secure insurers. Limits of insurance are based on engineering risk assessments and deductibles are set at levels that reflect our ability to retain the risk.

CORPORATE RESPONSIBILITY

Petro-Canada regards high standards of corporate responsibility as sound business practice. Responsible environmental stewardship reduces costs, and supports our license to operate. A safe and healthy workplace increases productivity, and investing in the communities where we operate builds support for our activities. Our *Code of Business Conduct* outlines the expected standards of behaviour and ethics in all of our business endeavours.

Environment, Health & Safety

Petro-Canada's executives are responsible for developing operational procedures and standards in compliance with our environment, health and safety policies and Total Loss Management (TLM) standards. Our Executive Leadership Team reviews environmental performance three times annually. In addition, a new Environment, Health & Safety committee of the Board of Directors was formed late in 2000 to provide additional oversight.

In 2000, we invested $121 million in environmental programs; $78 million for operating expenses and $43 million in capital expenditures for facility upgrades. We expect environmental costs to remain high, as we prepare to meet new federal limits for sulphur in gasoline, future fuel reformulation issues, and tighter standards for oil and gas production.

Underpinning the drive to consistently improve environmental performance is our TLM framework, under which we conduct a major internal audit for each business unit every four years. In 2000, audits were completed in the Foothills region of Western Canada Development & Operations, Sales & Marketing in Quebec and Atlantic Canada, and the Edmonton and Montreal refineries. Priority improvement opportunities were identified in each of these businesses and action plans are being implemented.

Since 1998, we have employed Life Cycle Value Assessment (LCVA), a tool created in concert with the Pembina Institute for Appropriate Development, to assess environmental impacts and costs over the full life cycle of a given project. LCVA is helping us design more environmentally considerate developments for the future, by identifying ways to reduce greenhouse gas (GHG) and other emissions while reducing costs. Terra Nova and MacKay River are two developments that will benefit from design and operational opportunities identified through this process.

Petro-Canada is committed to reducing greenhouse gas emissions in our ongoing Upstream and Downstream operations, primarily through continuing improvements in energy efficiency. At year-end 1999 (the latest year for which data are available), our GHG emissions were about four per cent less than in 1990, despite a 39 per cent increase in production during the same period. We surpassed our target of improving our energy efficiency by one per cent per year from 1994 to 1999. We have extended that commitment to 2005, with the awareness that additional initiatives will be more costly to implement and results more difficult to achieve.

Petro-Canada is an active participant in Canada's Voluntary Challenge and Registry (VCR) program. For the second year running, we received Gold Champion Level recognition for our 2000 Climate Change Progress Report. We have joined the newly established VCR Champions in Action program, which will test and implement enhanced voluntary approaches and measures to accelerate early action to reduce GHG emissions.

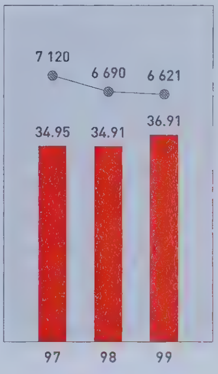
We are also reducing emissions of benzene and other volatile organic compounds in our Upstream and Downstream operations. Through initiatives such as improved leak detection and repair at our refineries, our benzene emissions totaled just 46.4 tonnes in 1999, a 37 per cent reduction from 1998.

Reducing natural gas flaring continues to be an environmental priority. Engineering assessments are planned at a number of Western Canada facilities and our Wilson Creek plant is being enhanced to process sour gas that was previously flared.

The safety and well-being of our employees is another essential component of strong performance. In 2000, our Employee Recordable Injury Frequency (per 200 000 person-hours) fell to 0.94 from 1.01 in 1999. Recordable injuries dropped from 48 in 1999 to 40 in 2000.

GREENHOUSE GAS EMISSIONS VERSUS PRODUCTION

Investments to improve energy efficiency have reduced total greenhouse gas emissions.



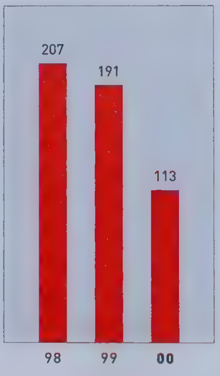
■ Total Upstream and Downstream production *(million cubic metres of oil equivalent/year)*

● GHG emissions *(kilotonnes/year)*

– 2000 data is not yet available.

EMISSIONS PERMIT EXCEEDANCES

Success in maintaining high plant reliability has reduced exceedances, which primarily result from operational upsets.



■ Number of permit exceedances

Community Investment

Petro-Canada's success as an energy company depends on the support of Canadians. We are determined to earn that support, not just through excellence in meeting customer needs, but also by playing a significant role in Canadian life.

As an Imagine Caring company, we make charitable investments on an annual basis that equate to at least one per cent of our pre-tax profits, on a five-year rolling average. In 2000, we contributed $5.2 million (1.2 per cent of pre-tax profits over five years) to nearly 300 non-profit organizations.

We continue to focus on the development of Canadian talent, expertise and innovation through education. We emphasize that theme within our four funding categories: education, health and community services, arts and culture, environment. We are also a major supporter of amateur sport through our partnership with the Canadian Olympic Association.

Petro-Canada employees and retirees are making a difference in the communities in which they live and work. In 2000, through our *Volunteer Energy* program, Petro-Canada provided 373 grants totaling $186 500 to non-profit organizations across Canada.

Community investment highlights in 2000 included:

- A $500 000 contribution to the Canadian Cancer Society's toll-free information line and the launch in April of our Petro-Points for Cancer initiative. By year-end, Petro-Canada customers had donated 6.4 million Petro-Points to this worthy cause.

- A major donation of 800 works from Petro-Canada's contemporary art collection. Culturally significant works were donated to institutions and museums, and an online employee auction generated $160 000 to create a fine arts scholarship at the Alberta College of Art & Design. Early in 2001, a public auction raised $225 000 for the Calgary Children's Initiative and art in three other Petro-Canada locations was also donated to children's charities.

- The launch of three new partnerships — with the Canadian Olympic Association, the Canadian Paralympic Committee, and the Coaching Association of Canada — to strengthen our support of Canadian amateur sport.

World Business Council for Sustainable Development

Imagine A Caring Company

vcr-mvr inc. Gold™ Champion Level Reporter

MANAGEMENT'S RESPONSIBILITY FOR THE FINANCIAL STATEMENTS

The preparation and presentation of the Company's consolidated financial statements is the responsibility of management. The financial statements have been prepared in accordance with generally accepted accounting principles and necessarily include estimates which are based on management's best judgments. Information contained elsewhere in the Annual Report is consistent, where applicable, with that contained in the financial statements.

Management is also responsible for installing and maintaining a system of internal controls to provide reasonable assurance that assets are safeguarded and that reliable financial information is produced for preparation of financial statements.

Arthur Andersen LLP, a firm of chartered accountants, were appointed by the shareholders as external auditors to conduct an independent examination and express their opinion on the consolidated financial statements. The Auditors' Report outlines the auditors' opinion and the scope of their examination. The Company has also contracted Arthur Andersen LLP to provide other audit services, including a review of the system of internal controls to ensure that there are no significant weaknesses.

The Board of Directors is responsible for overseeing management's performance of its responsibilities for financial reporting and internal control. The Board exercises this responsibility with the assistance of the Audit, Finance and Risk Committee of the Board.

R.A. Brenneman

Ronald A. Brenneman
President and Chief Executive Officer

E.F.H. Roberts

Ernest F.H. Roberts
Senior Vice-President and Chief Financial Officer

January 31, 2001

AUDIT, FINANCE AND RISK COMMITTEE OF THE BOARD OF DIRECTORS

The Board of Directors exercises its responsibility for overseeing management's performance of its financial reporting and internal control responsibilities with the assistance of the Audit, Finance and Risk Committee of the Board.

The Committee, which is composed of not less than three (currently five) directors who are not employees of the Company, reviews the annual consolidated financial statements prior to their approval by the Board. The Committee also reviews financial information contained in prospectuses and in reports filed with regulatory authorities, as required, as well as quarterly financial information.

With respect to the external auditors, the Committee reviews the terms of engagement, the annual audit plan, the Auditors' Report and the results of the audit. The Committee also recommends to the Board a firm of external auditors to be appointed by the shareholders.

With respect to Arthur Andersen LLP's engagement as contract auditor to review the system of internal controls, the Committee receives periodic reports, reviews significant findings and recommendations and approves their engagement contract and annual review plan.

The Committee also reviews and makes recommendations to the Board regarding practices in place for managing risk, insurance coverage, proposals for equity and debt financings and other matters which could materially affect the Company's financial or corporate structure.

Senior management, the external auditor and the contract auditor attend all Audit, Finance and Risk Committee meetings and each is provided with the opportunity to meet privately with the Committee.

Claude Fontaine

Claude Fontaine
Chairman of the Audit, Finance and Risk Committee

January 31, 2001

AUDITORS' REPORT

To the Shareholders of Petro-Canada:

We have audited the consolidated balance sheet of Petro-Canada as at December 31, 2000 and 1999 and the consolidated statements of earnings, retained earnings and cash flows for each of the three years in the period ended December 31, 2000. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2000 and 1999 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2000 in accordance with Canadian generally accepted accounting principles.

Arthur Andersen LLP

Arthur Andersen LLP
Chartered Accountants
Calgary, Alberta

January 31, 2001

CONSOLIDATED STATEMENT OF EARNINGS

(stated in millions of Canadian dollars)

For the years ended December 31,	**2000**	1999	1998
REVENUE			
Operating	**$ 9 372**	$ 6 095	$ 4 951
Investment and other income (Note 5)	**149**	52	65
	9 521	6 147	5 016
EXPENSES			
Crude oil and product purchases	**5 537**	3 436	2 413
Producing, refining and marketing	**1 288**	1 236	1 309
General and administrative (Note 6)	**277**	221	265
Exploration	**171**	78	95
Depreciation, depletion and amortization	**584**	558	530
Taxes other than income taxes	**54**	55	63
Interest	**144**	141	122
	8 055	5 725	4 797
EARNINGS BEFORE INCOME TAXES	**1 466**	422	219
PROVISION FOR INCOME TAXES (Note 7)			
Current	**363**	147	166
Future	**210**	42	(42)
	573	189	124
NET EARNINGS	**$ 893**	$ 233	$ 95
EARNINGS PER SHARE (dollars) (Note 8)	**$ 3.28**	$ 0.86	$ 0.35

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

(stated in millions of Canadian dollars)

For the years ended December 31,	**2000**	1999	1998
RETAINED EARNINGS AT BEGINNING OF YEAR, as previously reported	**$ 288**	$ 147	$ 139
Adjustment for the cumulative effect of change in accounting policy on prior periods (Note 3)	**(175)**	—	—
RETAINED EARNINGS AT BEGINNING OF YEAR, as restated	**113**	147	139
Net earnings	**893**	233	95
Dividends on common and variable voting shares	**(109)**	(92)	(87)
RETAINED EARNINGS AT END OF YEAR	**$ 897**	$ 288	$ 147

CONSOLIDATED STATEMENT OF CASH FLOWS

(stated in millions of Canadian dollars)

For the years ended December 31,	**2000**	1999	1998
OPERATING ACTIVITIES			
Net earnings	**$ 893**	$ 233	$ 95
Items not affecting cash flow (Note 9)	**806**	653	640
Exploration expenses (Note 13)	**171**	78	95
Cash flow	**1 870**	964	830
Decrease (increase) in operating working capital related to operating activities and other (Note 10)	**87**	(148)	184
Cash flow from operating activities	**1 957**	816	1 014
INVESTING ACTIVITIES			
Expenditures on property, plant and equipment and exploration	**(1 203)**	(1 021)	(1 116)
Proceeds from sales of assets (Note 5)	**722**	81	505
Increase in deferred charges and other assets, net	**(8)**	(5)	(17)
(Increase) decrease in operating working capital related to investing activities (Note 10)	**(44)**	(13)	54
	(533)	(958)	(574)
FINANCING ACTIVITIES AND DIVIDENDS			
Dividends on common and variable voting shares	**(109)**	(92)	(87)
Purchase of common and variable voting shares (Note 17)	**(134)**	—	—
Proceeds from issue of common and variable voting shares	**33**	6	6
Reduction of long-term debt	**(4)**	(3)	(390)
Proceeds from issue of long-term debt	**—**	—	387
(Increase) decrease in operating working capital related to financing activities and dividends (Note 10)	**(1)**	6	—
	(215)	(83)	(84)
INCREASE (DECREASE) IN CASH AND SHORT-TERM INVESTMENTS	**1 209**	(225)	356
CASH AND SHORT-TERM INVESTMENTS AT BEGINNING OF YEAR	**206**	431	75
CASH AND SHORT-TERM INVESTMENTS AT END OF YEAR	**$ 1 415**	$ 206	$ 431

CONSOLIDATED BALANCE SHEET

(stated in millions of Canadian dollars)

As at December 31,	**2000**	1999
ASSETS		
CURRENT ASSETS		
Cash and short-term investments (Note 11)	**$ 1 415**	$ 206
Accounts receivable	**1 289**	941
Inventories (Note 12)	**455**	501
Prepaid expenses	**20**	25
	3 179	1 673
PROPERTY, PLANT AND EQUIPMENT, NET (Note 13)	**6 660**	6 719
DEFERRED CHARGES AND OTHER ASSETS (Note 14)	**291**	269
	$ 10 130	$ 8 661
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	**$ 1 561**	$ 1 307
Income taxes payable	**194**	72
Current portion of long-term debt	**454**	4
	2 209	1 383
LONG-TERM DEBT (Note 15)	**1 320**	1 707
DEFERRED CREDITS AND OTHER LIABILITIES (Note 16)	**477**	355
FUTURE INCOME TAXES (Notes 3 and 7)	**1 533**	1 133
COMMITMENTS AND CONTINGENT LIABILITIES (Note 22)		
SHAREHOLDERS' EQUITY (Notes 3 and 17)	**4 591**	4 083
	$ 10 130	$ 8 661

Approved on behalf of the Board

R.A. Brenneman

Ronald A. Brenneman
Director

Claude Fontaine

Claude Fontaine
Director

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(tabular amounts stated in millions of Canadian dollars)

Note 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of Presentation The consolidated financial statements include the accounts of Petro-Canada and of all subsidiary companies ("the Company") and comply in all material respects with Canadian generally accepted accounting principles.

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingencies at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

(b) Cash and Short-Term Investments Cash and short-term investments comprise cash in the bank, less outstanding cheques, and deposits with a maturity of less than one year.

(c) Inventories Inventories are stated at the lower of cost and net realizable value. Cost of crude oil and products is determined primarily on a "last-in, first-out" basis.

(d) Investments Investments in companies over which the Company has significant influence are accounted for on the equity method. Other long-term investments are accounted for on the cost method.

(e) Property, Plant and Equipment Investments in exploration and development activities are accounted for on the successful efforts method. Under this method the acquisition cost of unproved acreage is capitalized. Costs of exploratory wells are initially capitalized pending determination of proved reserves and costs of wells which are assigned proved reserves remain capitalized while costs of unsuccessful wells are charged to earnings. All other exploration costs are charged to earnings as incurred. Development costs, including the cost of all wells, are capitalized.

Substantially all of the Company's exploration and development activities are conducted jointly with others. Only the Company's proportionate interest in such activities is reflected in the financial statements.

The interest cost of debt attributable to the construction of major new facilities is capitalized during the construction period.

(f) Depreciation, Depletion and Amortization Depreciation and depletion of capitalized costs of oil and gas producing properties are calculated using the unit of production method.

Depreciation of other plant and equipment is provided on either the unit of production method or the straight line method, based on the estimated service lives of the related assets, as appropriate.

The carrying amounts of unproved properties are evaluated for impairment with any such impairment being charged to earnings.

(g) Future Removal and Site Restoration Costs Estimated future removal and site restoration costs which are probable and can be reasonably determined are provided for on either the unit of production method or the straight line method, based on the estimated service lives of the related assets, as appropriate. Future removal and site restoration costs for inactive downstream sites, net of expected recoveries, are provided for at the time a decision is made to decommission the site.

(h) Translation of Foreign Currency Monetary assets and liabilities are translated into Canadian dollars at rates of exchange in effect at the balance sheet date. Other assets and related depreciation, depletion and amortization, other liabilities, revenue and other expense items are translated at rates of exchange in effect at the respective transaction dates. The resulting exchange gains or losses are included in earnings, except for unrealized exchange gains or losses arising on translation of long-term debt, which are deferred and amortized over the remaining term of the debt.

Foreign operations are integrated with the Company's other activities and are translated in the manner described above.

(i) Hedging Activity The Company may use derivative instruments to reduce its exposure to foreign exchange, interest rate and commodity price fluctuations. Gains and losses on these contracts, all of which constitute effective hedges, are deferred and recognized as a component of the related transaction.

(j) Stock Option Plan The Company maintains a stock option plan for directors, officers and certain employees. Consideration paid on exercise of stock options is credited to common and variable voting shares and no compensation expense is recognized when stock options or stock are issued.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (TABULAR AMOUNTS STATED IN MILLIONS OF CANADIAN DOLLARS)

Note 2 SEGMENTED INFORMATION

The Company operates in two business segments:

Upstream, comprising: exploration, development, production, transportation and marketing activities for crude oil, natural gas, natural gas liquids, sulphur and oil sands.

Downstream, comprising: purchase and sale of crude oil; refining crude oil into oil products; and distribution and marketing of these and other purchased products.

	Upstream			Downstream		
	2000	1999	1998	**2000**	1999	1998
Revenue						
Sales to customers and other revenues	**$ 1 718**	$ 1 174	$ 944	**$ 7 782**	$ 4 975	$ 4 057
Inter-segment sales	**619**	516	492	**6**	14	11
Segment Revenue	**$ 2 337**	$ 1 690	$ 1 436	**$ 7 788**	$ 4 989	$ 4 068
Earnings						
Earnings (loss) before the following:	**$ 1 819**	$ 930	$ 618	**$ 644**	$ 335	$ 444
Depreciation, depletion and amortization	**384**	399	385	**187**	158	137
Exploration expense	**171**	78	95	**—**	—	—
Interest	**—**	—	—	**—**	—	—
Provision for (recovery of) income taxes						
— current	**236**	52	151	**231**	192	73
— future	**252**	152	(72)	**(46)**	(121)	65
Reorganization costs (Note 6)	**—**	—	—	**—**	—	—
Net Earnings (Loss)	**$ 776**	$ 249	$ 59	**$ 272**	$ 106	$ 169
Capital and Exploration Expenditures						
Property, plant and equipment and exploration expenditures	**$ 927**	$ 793	$ 818	**$ 264**	$ 220	$ 276
Deferred charges and other assets	**4**	(3)	15	**7**	(5)	(7)
	$ 931	$ 790	$ 833	**$ 271**	$ 215	$ 269
Total Assets	**$ 4 959**	$ 5 052	$ 4 635	**$ 3 609**	$ 3 301	$ 3 070
Capital Employed	**$ 2 920**	$ 3 525	$ 3 306	**$ 2 165**	$ 2 084	$ 1 958

Financial information by business segment is presented in the following table as though each segment were a separate business entity. Inter-segment transfers of products, which are accounted for at market value, are eliminated on consolidation. Shared Services includes investment income, interest expense and general corporate revenue and expense. Shared Services assets are principally cash and short-term investments and other general corporate assets.

Shared Services			Consolidated		
2000	1999	1998	**2000**	1999	1998
$ 21	$ (2)	$ 15	**$ 9 521**	$ 6 147	$ 5 016
—	—	—			
$ 21	$ (2)	$ 15			
$ (32)	$ (66)	$ (32)	**$ 2 431**	$ 1 199	$ 1 030
13	1	8	**584**	558	530
—	—	—	**171**	78	95
144	141	122	**144**	141	122
(81)	(97)	(40)	**386**	147	184
9	11	(31)	**215**	42	(38)
—	—	—	**38**	—	42
$ (117)	$ (122)	$ (91)	**$ 893**	$ 233	$ 95
$ 12	$ 8	$ 22	**$ 1 203**	$ 1 021	$ 1 116
(3)	13	9	**8**	5	17
$ 9	$ 21	$ 31	**$ 1 211**	$ 1 026	$ 1 133
$ 1 562	$ 308	$ 693	**$ 10 130**	$ 8 661	$ 8 398
$ 1 150	$ 98	$ 289	**$ 6 235**	$ 5 707	$ 5 553

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (TABULAR AMOUNTS STATED IN MILLIONS OF CANADIAN DOLLARS)

Note 3 CHANGES IN ACCOUNTING POLICY

Effective January 1, 2000 the Company adopted the recommendations of the Canadian Institute of Chartered Accountants on accounting for future income taxes and on accounting for employees' future benefits. The change in accounting policy for future income taxes has been adopted retroactively and retained earnings as at January 1, 2000 has been reduced by $175 million, while the liability for future income taxes has been increased by the same amount; prior periods have not been restated. The change in accounting policy for employees' future benefits has been adopted prospectively.

The effect of the change in accounting policy for future income taxes has been to increase 2000 net earnings by $30 million and the effect of the change in accounting policy for employees' future benefits has been to reduce 2000 net earnings by $3 million.

Note 4 TAXES AND CROWN ROYALTIES

In addition to the provision for income taxes and other taxes included in the consolidated statement of earnings, the following items have been collected or produced on behalf of governments and have been paid or are payable by the Company:

	2000	1999	1998
Provincial fuel and sales taxes	**$ 1 511**	$ 1 464	$ 1 418
Federal excise taxes	**832**	839	819
Goods and Services Tax collected	**894**	632	602
Crown royalties, paid and paid in kind	**425**	171	125
	$ 3 662	$ 3 106	$ 2 964

Note 5 DISPOSALS OF ASSETS

Investment and other income includes net gains (losses) on disposal of assets of $73 million (1999 — $3 million; 1998 — $(3) million). The 2000 gains on disposal of assets consist of net gains on disposal of natural gas liquids assets, non-core oil and gas properties and other assets. The 1999 gains on disposal of assets consist of net gains on disposal of non-core oil and gas properties and other assets. The 1998 loss on disposal of assets net consists of a loss on the planned disposal of closed retail sites partially offset by gains on disposal of the Company's investment in Petro-Canada Centre, the Company's wholly-owned subsidiary, ICG Propane Inc., non-core oil and gas properties and other assets.

Note 6 GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses in 2000 includes a provision of $66 million for staff reductions and related building expenses. The provision decreased 2000 net earnings by $38 million.

General and administrative expenses in 1998 includes a provision of $64 million for the reorganization of the Company's downstream administration. The provision decreased 1998 net earnings by $42 million.

Note 7 INCOME TAXES

The computation of the provision for income taxes, which requires adjustment to earnings before income taxes for non-taxable and non-deductible items, is as follows:

	2000	1999	1998
Earnings before income taxes	**$ 1 466**	$ 422	$ 219
Add (deduct):			
Non-deductible royalties and other payments to provincial governments, net	**385**	170	130
Resource allowance	**(452)**	(213)	(123)
Equity in earnings of affiliates	**(10)**	(11)	(10)
Other	**4**	3	(13)
Non-deductible depreciation, depletion and amortization and disposals	**—**	70	125
Earnings as adjusted before income taxes	**$ 1 393**	$ 441	$ 328
Canadian Federal income tax rate	**38.0%**	38.0%	38.0%
Canadian Federal income tax on earnings as adjusted	**$ 529**	$ 168	$ 125
Large Corporations Tax	**15**	14	14
Provincial and other income taxes, net of federal abatement	**62**	28	14
Income tax credits and other	**(33)**	(21)	(29)
Provision for income taxes	**$ 573**	$ 189	$ 124
Effective income tax rate on earnings before income taxes	**39.1%**	44.8%	56.6%

Future income taxes consists of the following future income tax liabilities (assets) relating to temporary differences for:

	2000
Property, plant and equipment	**$ 1 372**
Partnership income	**514**
Inventories	**(176)**
Deferred credits and other liabilities	**(166)**
Deferred charges and other assets	**(16)**
Other	**5**
	$ 1 533

Prior periods were not restated by the Company when the new recommendations of the Canadian Institute of Chartered Accountants on accounting for income taxes were adopted effective January 1, 2000 (Note 3).

Complex income tax issues which involve interpretations of continually changing regulations are encountered in computing the provision for income taxes. Management believes that adequate provision has been made for all such outstanding issues.

Note 8 EARNINGS PER SHARE

The basic earnings per share, based on the weighted average number of common and variable voting shares outstanding in 2000 of 272.3 million (1999 — 271.5 million; 1998 — 271.2 million), for the year ended December 31, 2000 was $3.28 (1999 — $0.86; 1998 — $0.35). Fully diluted earnings per share, calculated on the assumption that all outstanding stock options were exercised, was $3.22 (1999 — $0.86; 1998 — $0.35).

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (TABULAR AMOUNTS STATED IN MILLIONS OF CANADIAN DOLLARS)

Note 9 ITEMS NOT AFFECTING CASH FLOW

	2000	1999	1998
Depreciation, depletion and amortization	$ 584	$ 558	$ 530
Future income taxes	210	42	(42)
Provision for future removal and site restoration costs	30	29	28
Amortization of unrealized foreign exchange losses	24	21	24
(Gain) loss on disposal of assets	(73)	(3)	3
Reclassification of current income taxes to proceeds from sales of assets (Note 5)	11	—	87
Other	20	6	10
	$ 806	$ 653	$ 640

Note 10 DECREASE (INCREASE) IN OPERATING WORKING CAPITAL AND OTHER

	2000	1999	1998
Accounts receivable	$ (348)	$ (258)	$ 221
Income taxes recoverable	—	—	68
Inventories	46	(46)	55
Prepaid expenses	5	(10)	5
Accounts payable and accrued liabilities	254	244	(126)
Income taxes payable	122	(23)	95
Current portion of long-term liabilities and other	(37)	(62)	(56)
Sale of ICG Propane Inc.	—	—	(24)
	$ 42	$ (155)	$ 238

Operating working capital is comprised of working capital other than cash and short-term investments and current portion of long-term debt.

The decrease (increase) in operating working capital and other consists of changes related to operating activities, investing activities and financing activities and dividends.

Note 11 CASH AND SHORT-TERM INVESTMENTS

The Company's short-term investments are considered to be cash equivalents and are recorded at cost, which approximates market value.

	2000	1999
Cash	$ 119	$ 316
Less: outstanding cheques	151	116
	(32)	200
Short-term investments	1 447	6
	$ 1 415	$ 206

Cash payments for interest and income taxes were as follows:

	2000	1999	1998
Interest	$ 154	$ 152	$ 149
Income taxes	186	216	64

Note 12 INVENTORIES

	2000	1999
Crude oil, refined products and merchandise	**$ 370**	$ 414
Materials and supplies	**85**	87
	$ 455	$ 501

Note 13 PROPERTY, PLANT AND EQUIPMENT

	2000			1999			Capital Expenditures	
	Cost	Accumulated Depreciation, Depletion and Amortization	Net	Cost	Accumulated Depreciation, Depletion and Amortization	Net	2000	1999
Upstream								
Oil and gas								
Western Canada	**$ 3 474**	**$ 1 671**	**$ 1 803**	$ 3 908	$ 1 898	$ 2 010	**$ 341**	$ 248
Canada offshore	**2 106**	**221**	**1 885**	1 691	120	1 571	**315**	311
Foreign	**100**	**45**	**55**	384	94	290	**18**	33
Oil sands	**1 128**	**537**	**591**	1 034	514	520	**94**	107
Other	**23**	**11**	**12**	31	18	13	**10**	10
Natural gas liquids	**—**	**—**	**—**	298	201	97	**—**	6
	6 831	**2 485**	**4 346**	7 346	2 845	4 501	**778**	715
Downstream								
Refining	**2 851**	**1 574**	**1 277**	2 737	1 499	1 238	**119**	129
Marketing and other	**1 689**	**701**	**988**	1 556	634	922	**145**	91
	4 540	**2 275**	**2 265**	4 293	2 133	2 160	**264**	220
Other property, plant and equipment	**419**	**370**	**49**	415	357	58	**12**	8
	$ 11 790	**$ 5 130**	**$ 6 660**	$ 12 054	$ 5 335	$ 6 719	**$ 1 054**	$ 943

Interest capitalized during 2000 amounted to $12 million (1999 — $11 million; 1998 — $32 million).

Capital expenditures and exploration expenses charged to earnings are classified as investing activities in the consolidated statement of cash flows.

Costs of $912 million (1999 — $532 million) relating to the Terra Nova Project (Note 22(a)) and other non-producing Canada offshore projects are not currently being amortized.

The Company is party to an agreement for the time charter and operation of a vessel for the transportation of crude oil produced from Hibernia. The time charter is for an initial term of ten years ending in 2007, is extendible at the Company's option for an additional 15 years, is accounted for as a capital lease (Note 15) and is included in Canada offshore at a net cost of $82 million (1999 — $85 million).

Note 14 DEFERRED CHARGES AND OTHER ASSETS

	2000	1999
Translation adjustment on long-term debt	**$ 130**	$ 87
Investments	**65**	77
Deferred pension funding	**46**	55
Deferred financing costs	**18**	19
Other	**32**	31
	$ 291	$ 269

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (TABULAR AMOUNTS STATED IN MILLIONS OF CANADIAN DOLLARS)

Note 15 LONG-TERM DEBT

	Maturity	2000	1999
Debentures and notes			
8.60% unsecured notes (U.S. $300 million)	2001	**$ 450**	$ 433
9.25% unsecured debentures (U.S. $300 million)	2021	**450**	433
7.875% unsecured debentures (U.S. $275 million)	2026	**413**	397
7.00% unsecured debentures (U.S. $250 million)	2028	**375**	361
Capital lease (Note 13) [1]	2022	**86**	87
		1 774	1 711
Current portion		**454**	4
		$ 1 320	$ 1 707

1 The implicit rate of interest in the capital lease is 11.90%. The aggregate repayment will be $86 million (U.S. $58 million), including $4 million (U.S. $3 million) to $7 million (U.S. $5 million) in each of the next five years.

The minimum repayment of long-term debt, other than the capital lease, in the next five years will be a payment of $450 million (U.S. $300 million) in 2001.

Interest on long-term debt was $138 million in 2000 (1999 — $137 million; 1998 — $120 million).

Note 16 DEFERRED CREDITS AND OTHER LIABILITIES

	2000	1999
Future removal and site restoration costs	**$ 214**	$ 177
Post-retirement benefits	**126**	118
Long-term liabilities	**137**	60
	$ 477	$ 355

Note 17 SHAREHOLDERS' EQUITY

	2000	1999
Common and variable voting shares	**$ 1 238**	$ 1 223
Contributed surplus	**2 456**	2 572
Retained earnings	**897**	288
	$ 4 591	$ 4 083

The authorized share capital of the Company is comprised of an unlimited number of:

(a) Preferred shares issuable in series designated as Senior Preferred Shares
(b) Preferred shares issuable in series designated as Junior Preferred Shares
(c) Common and variable voting shares

The common share capital is comprised of two classes of common equity: common shares which may be held only by residents of Canada and variable voting shares which may be held only by non-residents of Canada. The common shares and the variable voting shares differ only in their voting entitlements. The common shares carry one vote per share. The variable voting shares carry between one vote per share and 1/3 of one vote per share, depending on the number of variable voting shares outstanding compared to the number of voting shares outstanding. If the number of variable voting shares exceeds 25% of the public float of voting shares, the vote per variable voting share decreases so that the variable voting shares as a class do not carry more than 25% of the aggregate outstanding votes attached to all voting shares in the public float.

Note 17 SHAREHOLDERS' EQUITY (continued)

Changes in common and variable voting shares were as follows:

	2000			1999		
	Shares	**Amount**	**Contributed Surplus**	Shares	Amount	Contributed Surplus
Balance at beginning of year	**271 773 250**	**$ 1 223**	**$ 2 572**	271 339 702	$ 1 217	$ 2 572
Issued for cash under employee stock option and share purchase plans	**1 990 365**	**33**	**—**	433 548	6	—
Purchased for cancellation	**(3 956 400)**	**(18)**	**(116)**	—	—	—
Balance at end of year	**269 807 215**	**$ 1 238**	**$ 2 456**	271 773 250	$ 1 223	$ 2 572

During the year ended December 31, 2000 the Company made a Normal Course Issuer Bid to repurchase up to a maximum of 22 million common and variable voting shares for cancellation. This program commenced on November 1, 2000 and will end on October 31, 2001. At December 31, 2000, 3 956 400 shares had been purchased for a total cost of $134 million. The excess of purchase cost over the carrying amount of the shares purchased is recorded as a reduction of contributed surplus.

Stock Option Plan

The Company maintains a stock option plan and may grant options to directors, officers and certain employees for up to 21 million common and variable voting shares. The stock options have a maximum term of 10 years, vest over periods of up to five years and are exercisable at the market prices for the shares on the dates that the options were granted.

Changes in the number of outstanding stock options were as follows:

	2000		1999	
	Shares	**Weighted-Average Exercise Price (dollars)**	Shares	Weighted-Average Exercise Price (dollars)
Balance at beginning of year	**6 701 011**	**$ 18**	5 359 451	$ 19
Granted	**1 984 800**	**23**	1 882 500	17
Exercised	**(1 832 160)**	**16**	(432 875)	13
Cancelled	**(88 050)**	**21**	(108 065)	19
Balance at end of year	**6 765 601**	**20**	6 701 011	18

The following stock options were outstanding as at December 31, 2000:

Options Outstanding				Options Exercisable	
Number	Range of Exercise Prices (dollars)	Weighted-Average Life (years)	Weighted-Average Exercise Price (dollars)	Number	Weighted-Average Exercise Price (dollars)
376 056	$ 8 to 13	1.9	$ 10	376 056	$ 10
2 228 245	14 to 18	6.9	16	1 478 008	16
2 670 225	20 to 25	8.0	21	1 382 488	21
1 491 075	26 to 34	7.7	27	981 206	26
6 765 601	8 to 34	7.5	20	4 217 758	20

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (TABULAR AMOUNTS STATED IN MILLIONS OF CANADIAN DOLLARS)

Note 18 EMPLOYEE FUTURE BENEFITS

The Company maintains pension plans with defined benefit and defined contribution provisions, and provides certain health care and life insurance benefits to its qualifying retirees. The actuarially determined cost of these benefits is accrued over the estimated service life of employees. The defined benefit provisions are generally based upon years of service and average salary during the final years of employment. Certain defined benefit options require employee contributions and the balance of the funding for the registered plans is provided by the Company, based upon the advice of an independent actuary. The defined contribution option provides for an annual contribution of 5% of each participating employee's pensionable earnings. Substantially all of the pension assets are invested in equity, fixed income and other marketable securities.

Benefit Plan Expense	Pension Plans			Other Post-Retirement Plans		
	2000	1999	1998	**2000**	1999	1998
(a) Defined benefit plans						
Employer current service cost	**$ 20**	$ 18	$ 19	**$ 3**	$ 2	$ 2
Interest cost	**69**	67	72	**10**	8	8
Expected return on plan assets	**(83)**	(90)	(122)	**—**	—	—
Amortization of transitional (asset) obligation	**(5)**	—	—	**1**	—	—
Amortization of past service costs (gains)	**—**	4	34	**—**	(1)	(1)
Amortization of net actuarial gains	**—**	(1)	(1)	**—**	(1)	—
	1	(2)	2	**14**	8	9
(b) Defined contribution plans	**6**	6	6			
Total expense	**$ 7**	$ 4	$ 8	**$ 14**	$ 8	$ 9
Benefit Plan Funding	**$ 6**	$ 6	$ 6	**$ 6**	$ 5	$ 5

Financial Status of Defined Benefit Plans	Pension Plans		Other Post-Retirement Plans	
	2000	1999	**2000**	1999
Fair value of plan assets	**$ 1 113**	$ 1 025	**$ —**	$ —
Accrued benefit obligation	**1 047**	875	**160**	105
Funded status — plan surplus (deficit)	**66**	150	**(160)**	(105)
Unamortized transitional (asset) obligation	**(49)**	—	**25**	—
Unamortized net actuarial (gains) losses	**29**	(103)	**9**	(13)
Accrued benefit asset (liability)	**$ 46**	$ 47	**$ (126)**	$ (118)
Reconciliation of Plan Assets				
Actuarial value of assets at beginning of year	**$ 1 025**	$ 966	**$ —**	$ —
Effect of change in accounting policy	**27**	—	**—**	—
Fair value of plan assets at beginning of year	**1 052**	966	**—**	—
Contributions	**7**	5	**—**	—
Benefits paid	**(55)**	(53)	**—**	—
Actual return on plan assets	**115**	113	**—**	—
Other	**(6)**	(6)	**—**	—
Fair value of plan assets at end of year	**$ 1 113**	$ 1 025	**$ —**	$ —
Reconciliation of Accrued Benefit Obligation				
Accrued benefit obligation at beginning of year	**$ 875**	$ 842	**$ 105**	$ 100
Effect of change in accounting policy	**76**	—	**40**	—
Accrued benefit obligation at beginning of year, as adjusted	**951**	842	**145**	100
Current service cost	**21**	19	**3**	2
Interest cost	**69**	67	**10**	8
Benefits paid	**(55)**	(53)	**(7)**	(5)
Actuarial losses	**61**	—	**9**	—
Accrued benefit obligation at end of year	**$ 1 047**	$ 875	**$ 160**	$ 105

Note 18 EMPLOYEE FUTURE BENEFITS (continued)

Funded Status

The funded status includes the following amounts in respect of plans that are not fully funded:

	Pension Plans		Other Post-Retirement Plans	
	2000	1999	**2000**	1999
Accrued benefit obligation	**$ 67**	$ 56	**$ 160**	$ 105
Fair value of plan assets	**—**	—	**—**	—
Plan deficit	**$ (67)**	$ (56)	**$ (160)**	$ (105)

Defined Benefit Plan Assumptions

	2000	1999	1998
Year-end obligation discount rate	**6.75%**	8.00%	9.00%
Pension expense discount rate	**7.25%**	8.00%	9.00%
Long-term rate of return on plan assets	**8.00%**	8.00%	9.00%
Rate of compensation increase, excluding merit increases	**2.50%** [1]	2.00%	3.00%
Annual increase in the per capita cost of other post-retirement benefits	**6.20%** [2]	4.80%	5.50%

1 3.0% in 2001 and thereafter.
2 4.2% in 2005 and thereafter.

Note 19 RELATED PARTY TRANSACTIONS

Transactions with the Government of Canada (which holds 18% of the Company's issued shares at December 31, 2000), its agencies and other related parties, are in the normal course of business and are therefore on the same terms as those accorded to non-related parties.

Note 20 FAIR VALUE OF FINANCIAL INSTRUMENTS

As at December 31, 2000 the fair value, the related method of determination and the carrying value of the Company's financial instruments were as follows:

Current Assets/Current Liabilities

The fair value of financial instruments included in current assets and current liabilities, excluding the current portion of long-term debt, approximates the carrying amount of these instruments due to their short maturity.

Long-Term Debt

The fair value of long-term debt is based on publicly quoted market values.

Derivative Instruments

The fair value of derivative instruments, which is based on quotes provided by brokers, represents an approximation of amounts that would be received or paid to counterparties to settle these instruments prior to maturity. The Company plans to hold all derivative instruments, outstanding as at December 31, 2000, to maturity.

	Carrying Amount	Fair Value
Financial instruments included in current assets and current liabilities	$ 1 143	$ 1 143
Long-term debt [1]	(1 774)	(1 869)
Derivative instruments	—	8

1 Excludes translation adjustment of $130 million (Note 14).

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (TABULAR AMOUNTS STATED IN MILLIONS OF CANADIAN DOLLARS)

Note 21 DERIVATIVE INSTRUMENTS

The Company is exposed to market risks resulting from fluctuations in foreign exchange, interest rates and commodity prices in the course of its normal business operations. The Company actively monitors its exposure to market fluctuations and may use derivative instruments to manage these risks, as it considers appropriate. These derivative instruments are entered into solely for hedging purposes.

Crude Oil and Products

The downstream business segment uses forward contracts and options to reduce exposure to margin fluctuations, including margins on fixed price product sales, and short-term price fluctuations on the purchase of foreign and domestic crude oil and refined products.

Natural Gas

The Company has entered into forward contracts to manage price exposure on fixed price sales of natural gas.

The Company's outstanding contracts for derivative instruments and related unrealized gains at December 31, 2000 were as follows:

	Quantity	Average Price[1]	Unrealized Gains	Maturity
Crude Oil and Products (millions of barrels)				
Crude oil — downstream	**4.9**	**$ 37.60**	**$ 3**	**2001/2002/2003**
Products — downstream	**0.1**	**56.84**	**—**	**2001**
			3	
Natural Gas (billions of cubic feet)				
Natural gas — bought	**0.4**	**5.85[2]**	**5**	**2001**
			$ 8	

1 Canadian dollars per barrel or per thousand cubic feet, as applicable.
2 Represents the volume-weighted average prices at plant gate.

Derivative instruments involve a degree of credit risk which the Company controls through the establishment of credit policies and limits and the selection of financially sound counterparties. Market risk relating to changes in value or settlement cost of the Company's derivative instruments is essentially offset by gains or losses on the hedged positions.

Note 22 COMMITMENTS AND CONTINGENT LIABILITIES

(a) The Company is a participant in the project to develop the Terra Nova offshore oil field. Costs to production start-up are estimated at $2.45 billion; the Company's share is expected to be approximately $753 million (before investment tax credits), of which $700 million had been expended to December 31, 2000. The Company's share of development costs subsequent to start-up is estimated at $223 million, which is expected to be financed by cash flow from the project.

(b) The Company has leased property and equipment under various long-term operating leases for periods up to 2013. The minimum annual rentals for non-cancellable operating leases are estimated at $85 million in 2001, $70 million in 2002, $55 million in 2003, $50 million in 2004, $44 million in 2005 and $42 million per year thereafter until 2013.

(c) The Company is involved in litigation and claims associated with normal operations. Management is of the opinion that any resulting settlements would not materially affect the financial position of the Company.

Note 23 GENERALLY ACCEPTED ACCOUNTING PRINCIPLES ("GAAP") IN THE UNITED STATES

The Company's consolidated financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") in Canada, which differ in some respects from those applicable in the United States. The following are the significant differences in accounting principles as they pertain to the accompanying consolidated financial statements:

(a) Effective January 1, 2000 the Company adopted the recommendations of the Canadian Institute of Chartered Accountants on accounting for future income taxes and changed from the deferral method to the liability method (Note 3). This liability method differs from United States GAAP due to the application of transitional provisions and the accounting for certain Canadian income tax credits and allowance.

(b) The Company defers unrealized gains and losses on translation of long-term debt payable in foreign currencies for amortization over the remaining term of the debt. Under United States GAAP gains or losses on the translation of long-term debt payable in foreign currencies would be credited or charged to earnings with no deferral.

(c) United States GAAP requires that interest be capitalized as part of the cost of certain assets while they are being prepared for their intended use. The Company capitalizes interest attributable to the construction of major new facilities and does not capitalize interest on all assets which would require interest capitalization under United States GAAP.

(d) In prior years the Company transferred amounts from contributed surplus to the accumulated deficit. Under United States GAAP these transfers would not have occurred.

(e) United States GAAP utilizes the concept of comprehensive income which includes items not included in net earnings. The Company's net earnings under United States GAAP is the same as its comprehensive income.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (TABULAR AMOUNTS STATED IN MILLIONS OF CANADIAN DOLLARS)

Note 23 GENERALLY ACCEPTED ACCOUNTING PRINCIPLES ("GAAP") IN THE UNITED STATES (continued)

The application of United States GAAP would have the following effects on earnings as reported:

	2000	1999	1998
Net earnings as reported in the consolidated statement of earnings	**$ 893**	$ 233	$ 95
Adjustments, net of applicable income taxes			
Accounting for income taxes	**(35)**	3	(2)
Foreign currency translation	**(34)**	85	(46)
Capitalization of interest and related amortization	**14**	11	21
Other	**1**	(1)	1
Net earnings, as adjusted	**$ 839**	$ 331	$ 69
Earnings per share, as adjusted — basic	**$ 3.08**	$ 1.22	$ 0.25
Earnings per share, as adjusted — diluted	**$ 3.06**	$ 1.22	$ 0.25

The application of United States GAAP would have the following effects on the consolidated balance sheets as reported:

	As Reported	Increase (Decrease)	United States GAAP
December 31, 2000			
Current assets	**$ 3 179**	**$ —**	**$ 3 179**
Property, plant and equipment, net	**6 660**	**551**	**7 211**
Deferred charges and other assets	**291**	**(137)**	**154**
Current liabilities	**2 209**	**—**	**2 209**
Long-term debt	**1 320**	**—**	**1 320**
Deferred credits and other liabilities	**477**	**—**	**477**
Future income taxes	**1 533**	**238**	**1 771**
Common and variable voting shares	**1 238**	**—**	**1 238**
Contributed surplus	**2 456**	**1 122**	**3 578**
Retained earnings (deficit)	**897**	**(946)**	**(49)**
December 31, 1999			
Current assets	$ 1 673	$ —	$ 1 673
Property, plant and equipment, net	6 719	561	7 280
Deferred charges and other assets	269	(95)	174
Current liabilities	1 383	—	1 383
Long-term debt	1 707	—	1 707
Deferred credits and other liabilities	355	—	355
Future income taxes	1 133	411	1 544
Common and variable voting shares	1 223	—	1 223
Contributed surplus	2 572	1 122	3 694
Retained earnings (deficit)	288	(1 067)	(779)

Net Proved Developed and Undeveloped Reserves Before Royalties[1,2]

	Crude Oil And Field Natural Gas Liquids (millions of barrels)					Natural Gas (billions of cubic feet)
	Western Canada	International[4,5]	East Coast[6]	Synthetic Crude Oil and Bitumen[7]	Total	Total
Beginning of year 1999	118	13	16	329	476	2 503
Revisions of previous estimates	5	—	—	—	5	(16)
Sale of reserves in place	(5)	—	—	—	(5)	(47)
Purchase of reserves in place	—	—	—	—	—	9
Discoveries, extensions and improved recovery	5	4	25	—	34	295
Production	(13)	(4)	(7)	(10)	(34)	(263)
End of year 1999	110	13	34	319	476	2 481
Revisions of previous estimates	21	(2)	—	10	29	(40)
Sale of reserves in place	(75)	(10)	—	—	(85)	(180)
Purchase of reserves in place	—	—	—	—	—	—
Discoveries, extensions and improved recovery	6	6	15	—	27	341
Production	(8)	(5)	(11)	(9)	(33)	(271)
End of year 2000	**54**	**2**	**38**	**320**	**414**	**2 331**

Net Probable Reserves Before Royalties[1,3]

	Crude Oil And Field Natural Gas Liquids (millions of barrels)					Natural Gas (billions of cubic feet)
	Western Canada	International[4,5]	East Coast[6]	Synthetic Crude Oil and Bitumen[7]	Total	Total
End of year 1999	39	37	207	133	416	1 157
Revisions of previous estimates	—	(8)	—	248	240	129
Sale of reserves in place	(15)	(8)	—	—	(23)	(96)
Purchase of reserves in place	—	—	19	—	19	—
Discoveries, extensions and improved recovery	(1)	2	(15)	—	(14)	(112)
End of year 2000	**23**	**23**	**211**	**381**	**638**	**1 078**

1 Net proved developed and undeveloped and probable reserves before royalties are Petro-Canada's working interest in reserves before the deduction of Crown or other royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production. No reserve quantities have been included to reflect royalty interests Petro-Canada has in various properties.

2 Proved reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those proved reserves that are expected to be recovered from existing wells or facilities. Proved undeveloped reserves are proved reserves which are not recoverable from existing wells or facilities, but which are expected to be recovered through additional development drilling or through the upgrading of existing or additional new facilities.

3 Unproved reserves are based on geological and/or engineering data similar to that used in estimates of proved reserves, but technical, contractual, economic or regulatory uncertainties preclude such reserves being classified as proved. Unproved reserves may be further classified as probable reserves and possible reserves. Probable reserves are less certain than proved reserves and can be estimated with a degree of certainty sufficient to indicate they are more likely to be recovered than not.

4 Year-end 2000 international proved and probable reserves are in Algeria.

5 After deduction of a 20 per cent royalty, Petro-Canada receives crude oil to recover costs incurred on behalf of Petro-Canada and SONATRACH, the Algerian state oil company. The remaining production is shared between Petro-Canada and SONATRACH, varying with the level of production. The total share accruing to Petro-Canada cannot exceed 49 per cent of gross production volumes.

6 Proved and probable reserves at Hibernia and Terra Nova are based on primary recovery for drilled fault blocks and undrilled fault blocks which lie between drilled fault blocks and incremental recovery in fault blocks showing response to water or gas injection.

7 Proved and probable reserves of synthetic crude oil are based on high geological certainty, with drilling hole spacing less than 700 metres and application of existing or piloted technology. For proved reserves, appropriate co-owner and regulatory approvals are in place. For probable reserves, appropriate co-owner approvals are in place and regulatory approvals are being sought.

Principal Reserve and Production Locations

Crude Oil[1] Fields	Proved Reserves Before Royalties at December 31, 2000 (millions of barrels)	Per Cent of Total Proved Oil Reserves	Average 2000 Daily Production Before Royalties[2] (thousands of barrels)	Per Cent of Total 2000 Daily Oil Production
Syncrude, Alberta	320.0	83.1	24.3	31.1
Hibernia, offshore Newfoundland	30.2	7.8	28.9	37.0
Ferrier, Alberta	14.1	3.7	3.8	4.9
Terra Nova, offshore Newfoundland	7.6	2.0	—	—
Willesden Green, Alberta	6.1	1.6	2.0	2.5
Tamadanet, Algeria	2.0	0.5	3.7	4.7
Brazeau, Alberta	1.8	0.5	0.7	0.9
Gilby/Wilson Creek, Alberta	1.5	0.4	0.5	0.7
Ricinus/Bearberry area, Alberta	0.9	0.2	0.9	1.2
Hanlan area, Alberta	0.5	0.1	—	—
Other	0.6	0.1	13.4	17.0
Total	**385.3**	**100.0**	**78.2**	**100.0**

Natural Gas[1] Fields	Proved Reserves Before Royalties at December 31, 2000 (billions of cubic feet)	Per Cent of Total Proved Gas Reserves	Average 2000 Daily Production Before Royalties[2] (millions of cubic feet)	Per Cent of Total 2000 Daily Gas Production
Wildcat Hills area, Alberta	594.3	25.5	118.2	16.0
Hanlan area, Alberta	294.2	12.6	102.6	13.8
Jedney/Beg/Bubbles, British Columbia	224.2	9.6	41.3	5.6
Ricinus/Bearberry area, Alberta	190.8	8.2	97.7	13.2
Laprise area, British Columbia	131.9	5.7	40.3	5.4
Gilby/Wilson Creek, Alberta	106.5	4.6	37.8	5.1
Medicine Hat, Alberta	104.6	4.5	27.0	3.6
Alderson, Alberta	81.2	3.5	19.5	2.6
Brazeau, Alberta	78.1	3.4	51.8	7.0
Clarke Lake, British Columbia	72.0	3.1	32.3	4.4
Other	453.1	19.3	172.2	23.3
Total	**2 330.9**	**100.0**	**740.7**	**100.0**

1 Does not include natural gas liquids.
2 Includes Western Canada and Norway properties sold in 2000.

Oil and Gas Landholdings (Gross[1]/Net[2]) (millions of acres)

	Developed[3]		Undeveloped[4]		Total	
	Gross	Net	Gross	Net	Gross	Net
Mainland Canada[5]	2.2	1.1	3.7	2.4	5.9	3.5
Oil Sands	—	—	0.8	0.3	0.8	0.3
East Coast Offshore[6]	0.1	—	5.4	2.2	5.5	2.2
Other Canada	—	—	7.2	6.0	7.2	6.0
International	—	—	3.3	3.3	3.3	3.3
Total	**2.3**	**1.1**	**20.4**	**14.2**	**22.7**	**15.3**

1 Includes interests of others.
2 Excludes interests of others.
3 Areas capable of production.
4 Areas with rights to explore.
5 Includes Mackenzie Delta.
6 Includes a 0.46 million gross (0.23 million net) acre parcel acquired at the 2000 Newfoundland land sale, for which a licence was issued in the first quarter of 2001.

QUARTERLY FINANCIAL AND STOCK TRADING INFORMATION

(unaudited, stated in millions of dollars unless otherwise indicated)

	First Quarter 2000	Second Quarter 2000	Third Quarter 2000	Fourth Quarter 2000	First Quarter 1999	Second Quarter 1999	Third Quarter 1999	Fourth Quarter 1999
Revenue								
Operating	**$ 2 086**	**$ 2 133**	**$ 2 421**	**$ 2 732**	$ 1 086	$ 1 371	$ 1 673	$ 1 965
Investment and other income	**(153)**	**120**	**13**	**169**	19	19	14	—
	1 933	**2 253**	**2 434**	**2 901**	1 105	1 390	1 687	1 965
Expenses								
Crude oil and product purchases	**1 245**	**1 236**	**1 471**	**1 585**	520	715	967	1 234
Producing, refining and marketing	**312**	**308**	**320**	**348**	295	303	303	335
General and administrative [1]	**111**	**57**	**47**	**62**	57	60	51	53
Exploration	**30**	**32**	**38**	**71**	22	20	12	24
Depreciation, depletion and amortization	**161**	**133**	**127**	**163**	131	139	136	152
Taxes other than income taxes	**15**	**15**	**13**	**11**	15	13	15	12
Interest	**34**	**36**	**36**	**38**	33	35	36	37
	1 908	**1 817**	**2 052**	**2 278**	1 073	1 285	1 520	1 847
Earnings Before Income Taxes	**25**	**436**	**382**	**623**	32	105	167	118
Provision for Income Taxes	**6**	**177**	**153**	**237**	24	41	72	52
Net Earnings	**$ 19**	**$ 259**	**$ 229**	**$ 386**	$ 8	$ 64	$ 95	$ 66
Cash Flow	**$ 308**	**$ 428**	**$ 450**	**$ 684**	$ 165	$ 224	$ 260	$ 315
Segmented Earnings								
Earnings from operations								
Upstream	**$ 126**	**$ 149**	**$ 185**	**$ 244**	$ 7	$ 55	$ 83	$ 98
Downstream	**61**	**72**	**74**	**66**	31	35	40	9
Shared Services	**(39)**	**(28)**	**(27)**	**(23)**	(31)	(28)	(30)	(33)
Reorganization costs	**(33)**	**—**	**—**	**(5)**	—	—	—	—
	115	**193**	**232**	**282**	7	62	93	74
Gain (loss) on sale of assets	**(96)**	**66**	**(3)**	**104**	1	2	2	(8)
Net earnings	**$ 19**	**$ 259**	**$ 229**	**$ 386**	$ 8	$ 64	$ 95	$ 66
Share Information (dollars per share)								
Earnings								
— Basic	**0.07**	**0.95**	**0.84**	**1.42**	0.03	0.24	0.35	0.24
— Fully diluted	**0.07**	**0.94**	**0.82**	**1.39**	0.03	0.24	0.35	0.24
Cash flow	**1.13**	**1.57**	**1.65**	**2.52**	0.61	0.82	0.96	1.16
Dividends per share	**0.10**	**0.10**	**0.10**	**0.10**	0.08	0.08	0.08	0.10
Share price [2]								
— High	**25.30**	**31.15**	**35.80**	**38.45**	20.15	20.95	25.10	23.80
— Low	**19.00**	**22.60**	**26.40**	**30.80**	15.35	17.00	19.75	19.75
— Close (end of period)	**24.15**	**27.65**	**33.50**	**38.15**	17.65	20.10	22.25	20.45
Shares traded (millions) [3]	**57.0**	**57.9**	**54.9**	**55.0**	49.1	59.6	39.9	36.1

1 General and administrative expenses for 2000 includes a provision of $66 million before income taxes for reorganization costs.
2 Share prices are for trading on the Toronto Stock Exchange.
3 Total shares traded on the Toronto and New York stock exchanges.

FIVE-YEAR FINANCIAL AND OPERATING SUMMARY[1]

(stated in millions of dollars, unless otherwise indicated)

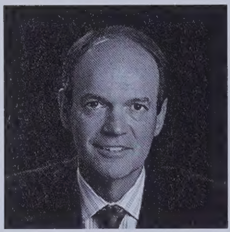
	2000	1999	1998	1997	1996
Consolidated					
Revenue	**$ 9 521**	$ 6 147	$ 5 016	$ 6 096	$ 5 607
Expenses	**8 055**	5 725	4 797	5 460	5 111
Provision for income taxes	**573**	189	124	330	249
Net earnings	**$ 893**	$ 233	$ 95	$ 306	$ 247
Cash flow	**1 870**	964	830	1 263	863
Total assets	**10 130**	8 661	8 398	8 338	7 769
Average capital employed	**5 884**	5 630	5 536	5 406	5 019
Operating return on capital employed (per cent) (in 2000 and 1998, before reorganization costs)	**16.0**	5.6	3.6	6.9	6.2
Return on capital employed (per cent)	**16.6**	5.6	3.0	6.8	6.2
Cash flow return on capital employed (per cent)	**33.2**	18.6	16.3	24.5	18.5
Debt	**1 774**	1 711	1 829	1 741	1 709
Debt to debt plus equity (per cent)	**27.9**	29.5	31.7	30.7	31.6
Debt to cash flow (times)	**0.9**	1.8	2.2	1.4	2.0
Expenditures on property, plant and equipment and exploration	**1 203**	1 021	1 116	1 049	959
Employees (number at year end)[2]	**4 024**	4 417	4 620	5 749	5 679
Shareholders' Data					
Weighted average number of common and variable voting shares outstanding (millions)[3]	**272.3**	271.5	271.2	270.9	262.3
Shares outstanding at year end (millions)	**269.8**	271.8	271.3	271.0	270.7
Publicly held shares at year end (millions)	**220.4**	222.4	221.9	221.6	221.3
Share prices (dollars)[4]					
— at year end	**38.15**	20.45	16.25	26.00	19.35
— range during the year	**19.00-38.45**	15.35-25.10	14.55-26.95	18.90-29.85	15.63-20.60
Shares traded (millions)[5]	**224.8**	184.7	244.7	271.1	112.7
Book value per share (dollars)	**17.02**	15.02	14.51	14.47	13.64

1 Certain reclassifications have been made to the figures previously reported to reflect subsequent changes in reporting presentation.
2 Numbers prior to 1998 include employees of ICG Propane Inc., a subsidiary that was sold in 1998.
3 Includes 49.4 million shares held as an investment by the Government of Canada.
4 Year-end price and range during 2000 are from the Toronto Stock Exchange.
5 Total shares traded on the Toronto and New York stock exchanges in 1999 and 2000.

	2000	1999	1998	1997	1996
Upstream Sector					
Earnings from operations	**$ 704**	$ 243	$ 29	$ 188	$ 192
Gain (loss) on sale of assets	**72**	6	30	(2)	4
Net earnings	**$ 776**	$ 249	$ 59	$ 186	$ 196
Cash flow	**1 538**	885	516	900	655
Expenditures on property, plant and equipment and exploration	**927**	793	818	805	649
Daily production (net, before royalties)					
Crude oil and field liquids (thousands of barrels)	**89.2**	95.3	101.1	95.1	97.3
Natural gas (excluding injectants, millions of cubic feet)	**738**	719	722	760	712
Ethane and natural gas liquids production from straddle plants (thousands of barrels)[1]	**5.8**	29.7	35.2	39.6	34.9
Average sale price					
Crude oil and field liquids (per barrel)[2]	**41.45**	24.58	17.72	25.79	25.16
Natural gas (per thousand cubic feet)[2,3]	**4.75**	2.59	1.96	1.85	1.61
Proved reserves (net, before royalties)					
Crude oil and field liquids (millions of barrels)	**414**	476	476	432	452
Natural gas (trillions of cubic feet)	**2.3**	2.5	2.5	2.5	2.6
Oil and gas landholdings (gross/net) (millions of acres)	**22.7/15.3**	22.0/14.9	19.2/13.3	17.3/12.0	16.7/11.7
Wells drilled (gross/net)					
Oil	**41/21**	51/13	76/33	127/65	118/82
Natural gas	**234/135**	164/95	188/83	145/82	141/73
Dry	**23/6**	26/8	23/9	34/21	39/17
Total	**298/162**	241/116	287/125	306/168	298/172
Downstream Sector					
Earnings from operations	**$ 273**	$ 115	$ 204	$ 225	$ 130
Loss on sale of assets	**(1)**	(9)	(35)	(6)	(3)
Net earnings	**$ 272**	$ 106	$ 169	$ 219	$ 127
Cash flow	**434**	163	420	415	243
Expenditures on property, plant and equipment	**264**	220	276	215	282
Petroleum product sales (thousands of cubic metres per day)	**55.4**	51.2	49.1	48.5	43.7
Retail outlets at year end	**1 618**	1 658	1 709	1 780	1 765
Refinery crude capacity at year end (thousands of cubic metres per day)	**49.8**	49.0	49.0	45.4	45.4
Average refinery utilization (per cent)	**101**	100	95	103	99

1 The natural gas liquids business was sold in the first quarter of 2000.
2 After the impact of hedging activities.
3 Before deduction of British Columbia gathering and processing charges.

EXECUTIVE LEADERSHIP TEAM



Ron Brenneman
President and Chief Executive Officer

Boris Jackman
Executive Vice-President (Downstream)

Norm McIntyre
Executive Vice-President (Upstream)

Harry Roberts
Senior Vice-President and Chief Financial Officer

BOARD OF DIRECTORS

Ronald A. Brenneman, a resident of Calgary, was appointed president and CEO and a director of Petro-Canada in January 2000. Mr. Brenneman has more than 30 years of industry experience in upstream, downstream and corporate roles, and has held senior executive positions with a major Canadian and international organization. He is a director of the Bank of Nova Scotia.

Angus A. Bruneau, a resident of St. John's, has been a director of Petro-Canada since 1996. Dr. Bruneau is chairman of Fortis Inc. He is a director of Inco Limited, the SNC-Lavalin Group Inc., Canada Life Assurance Company, and North Atlantic Pipeline Partners L.P. He is a member of the Natural Sciences and Engineering Research Council and the Canadian Foundation for Innovation, and serves on the board of the Nature Conservancy of Canada and the Council for Canadian Unity.

Gail Cook-Bennett [1], a resident of Toronto, has been a director of Petro-Canada since 1991. Dr. Cook-Bennett is chairperson of the Canada Pension Plan Investment Board. She is a director of Cadillac Fairview Inc., Enbridge Consumers Gas Company, Groupe Transcontinental G.T.C. Ltee., Mackenzie Financial Corporation and Manulife Financial.

John F. Cordeau, a resident of Calgary, has been a director of Petro-Canada since 1994. Mr. Cordeau is a partner and litigation department head at Bennett Jones LLP and a director of a number of private companies.

Purdy Crawford, a resident of Toronto, has been a director of Petro-Canada since 1995. Mr. Crawford is chairman of AT&T Canada Corp. and past chairman of Imasco Limited. He is a director of Camco Inc., Canadian National Railway Company, Inco Limited, Maple Leaf Foods Inc., Nova Scotia Power Inc. and the Venator Group Inc. He also serves as counsel to Osler, Hoskin & Harcourt.

Claude Fontaine [1], a resident of Montreal, has been a director of Petro-Canada since 1987. Mr. Fontaine is a senior partner and executive committee member with Ogilvy Renault. He is a director of Domtar Inc., Optimum General Inc., the Montreal Heart Institute Research Fund and the Council for Canadian Unity.

Thomas E. Kierans, a resident of Toronto, has been a director of Petro-Canada since 1991, and served as chairman of the board from 1996 until January 2000. Mr. Kierans is chairman of the Canadian Institute for Advanced Research, Moore Corporation Limited and the Toronto International Leadership Centre for Financial Sector Supervision. He is a director of Manufacturers Life Insurance Company, Fishery Products International Ltd., IPSCO Inc., Inmet Mining Corp., BCE Inc., CGI Group Inc. and Teleglobe Inc. He is advisor to North Limited and Corporation Lazard Canada.

Brian F. MacNeill [1], a resident of Calgary and a director of Petro-Canada since 1995, was appointed chairman in May 2000. Mr. MacNeill is past president and CEO of Enbridge Inc. He is a director of Enbridge Inc., the Toronto-Dominion Bank, Dofasco Inc., Western Oil Sands Inc., West Fraser Timber Co. Ltd. and Veritas DGC Inc. He is a member of the Alberta and Ontario institutes of chartered accountants and the Financial Executives Institute. He is a Fellow of the Canadian Institute of Chartered Accountants and a director and chair of the United Way of Calgary and Area.

Paul D. Melnuk [1], a resident of Toronto, joined Petro-Canada's board of directors in July 2000. Mr. Melnuk is president and CEO of Bracknell Corporation. He is a past president and CEO of Barrick Gold Corporation and Clark USA, Inc. He is a member of the Young Presidents' Organization, Upper Canada chapter.

Guylaine Saucier [1], a resident of Montreal, has been a director of Petro-Canada since 1991. Ms. Saucier is chairperson of the Joint Committee on Corporate Governance. She is a director of the Bank of Montreal, Nortel Networks Corporation, AXA Assurances Inc. and Tembec Inc. She is past chairperson of the Canadian Broadcasting Corporation and the Canadian Institute of Chartered Accountants.

William W. Siebens, a resident of Calgary, has been a director of Petro-Canada since 1986. Mr. Siebens is president and CEO of Candor Investments Ltd., and chairman of Freehold Royalty Trust. He is a director of the Fraser Institute.

1 Audit, Finance and Risk Committee member

INVESTOR INFORMATION

Outstanding Shares
At December 31, 2000, Petro-Canada's public float was 220.4 million shares, comprising 176.5 million common shares held by residents of Canada, and 43.9 million variable voting shares held by non-residents of Canada.

Transfer Agent and Registrar
In Canada:
CIBC Mellon Trust Company

In the United States:
ChaseMellon Shareholder Services, LLC

Telephone toll free: 1-800-387-0825
Fax: (416) 643-5660 or
(416) 643-5661
E-mail: inquiries@cibcmellon.com
Web site: www.cibcmellon.com

Duplicate Reports
Shareholders with more than one unregistered account may receive duplicate materials. To eliminate duplicate mailings, contact the transfer agent and registrar.

Annual and Special Meeting
The annual and special meeting of shareholders will be held at 11:00 a.m. local time
Tuesday, April 24, 2001
The Palliser Hotel, Crystal Ballroom
133-9th Avenue S.W.
Calgary, Alberta

Stock Exchange Listings and Symbols
Toronto: PCA
New York: PCZ

Dividends
Petro-Canada's Board of Directors has adopted a policy of paying quarterly dividends of $0.10 ($0.40 per annum) per common and variable voting share. The Board regularly reviews the dividend policy in light of the Company's financial position, its financing requirements for growth, and other factors.

On Our Web Site...
The following documents are available on Petro-Canada's Web site at www.petro-canada.ca

- Statistical Supplement
- Annual Information Form
- Quarterly Reports
- Proxy Circular
- Petro-Canada's Code of Business Conduct

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Fax: (403) 296-3030
Web site: www.petro-canada.ca

We'd Like Your Feedback
We invite your comments on our low-cost annual report format. Please e-mail your comments to: dcoll@petro-canada.ca

GLOSSARY OF FINANCIAL TERMS AND RATIOS

Terms
BARREL OF OIL EQUIVALENT: Natural gas production (excluding injectants) is converted using 6 000 cubic feet of gas for one barrel of oil.

CAPITAL EMPLOYED: Total of shareholders' equity and debt, less related foreign currency translation adjustment.

CASH FLOW: Cash flow from operations before changes in non-cash working capital items.

DEBT: Long-term debt including current portion.

EARNINGS FROM OPERATIONS: Earnings before gains (losses) on asset sales.

OPERATING EXPENSES: Producing, refining and marketing expenses.

OVERHEAD EXPENSES: General and administrative expenses.

Ratios
RETURN ON CAPITAL EMPLOYED: Net earnings plus after-tax interest expense divided by average capital employed. Measures net earnings relative to the asset base.

OPERATING RETURN ON CAPITAL EMPLOYED: Earnings from operations plus after-tax interest expense divided by average capital employed. Measures operating earnings relative to the asset base.

RETURN ON EQUITY: Net earnings divided by average shareholders' equity. Measures the return earned by shareholders on their investment in the Company.

CASH FLOW RETURN ON CAPITAL EMPLOYED: Cash flow plus after-tax interest expense divided by average capital employed. Measures cash flow generated relative to the asset base.

CURRENT RATIO: Current assets divided by current liabilities. Reflects the Company's short-term liquidity and its ability to pay short-term debts.

DEBT TO CASH FLOW: Debt divided by cash flow. Indicates the Company's ability to discharge its outstanding debt.

DEBT TO DEBT PLUS EQUITY: Debt divided by debt plus equity. Indicates the relative amount of debt in the Company's capital structure. Measures financial strength.

INTEREST COVERAGE: Measures the Company's ability to cover interest charges on debt.

Earnings basis: Earnings before interest expense and provision for income taxes divided by interest expense plus capitalized interest.

EBITDAX basis: Earnings before interest expense, income taxes, depreciation, depletion and amortization and exploration expenses divided by interest expense plus capitalized interest.

Cash flow basis: Cash flow before interest expense and current income taxes divided by interest expense plus capitalized interest.

Conversion Factors
To conform with common usage, imperial units of measurement are used in this report to describe exploration and production, while metric units are used for refining and marketing. Dollars are Canadian unless otherwise stated.

1 cubic metre (liquids) = 6.29 barrels
1 cubic metre (natural gas) = 35.49 cubic feet
1 litre = 0.22 imperial gallon
1 hectare = 2.47 acres
1 cubic metre = 1 000 litres

DESIGN: Bhandari & Plater Inc. PAGE 2 AND 3 PHOTOGRAPHY: (from left) Hibernia Management and Development Company Ltd., Chris Thomas, Syncrude Canada Ltd., Albert Normandin EXECUTIVE PHOTOGRAPHY: Bernard Bohn
This annual report was printed on paper that is acid-free and recyclable. Inks are based on linseed oil and contain no heavy metals. The printing process was alcohol-free.
Volatile organic compounds associated with printing were reduced by 50 to 75 per cent from the levels which would have been produced using traditional inks and processes.

WE ARE **FOCUSED** ON FOUR CORE BUSINESSES:

EAST COAST OFFSHORE	NATURAL GAS	OIL SANDS	DOWNSTREAM
A LEADING PLAYER IN GRAND BANKS DEVELOPMENT	PROFITABLY FINDING AND DEVELOPING A FUEL IN ROBUST DEMAND	TAPPING NEW RESOURCES WITH LEADING-EDGE TECHNOLOGY	BUILDING ON THE BRAND STRENGTH OF CANADA'S GAS STATION

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